BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2012-203-E

October ___, 2012

IN RE:	)	
	)	
Petition of South Carolina Electric &	)	
Gas Company for Updates and Revisions to	)	TABLE OF CONTENTS
Schedules Related to the Construction of a	)	
Nuclear Base Loan Generation Facility at	)	
Jenkinsville, South Carolina	)	
___________________________________	)	

BEFORE

THE PUBLIC SERVICE COMMISSION

OF

SOUTH CAROLINA

DOCKET NO. 2012-203-E

IN RE:	)	
	)	**<u>SCE&G'S BRIEF IN THE FORM OF A PROPOSED ORDER APPROVING SCE&G'S REQUEST FOR MODIFICATION OF SCHEDULES</u>**
Petition of South Carolina Electric & Gas Company for Updates and Revisions to Schedules Related to the Construction of a Nuclear Base Load Generation Facility at Jenkinsville, South Carolina	)	

I. <u>INTRODUCTION</u>

This matter comes before the Public Service Commission of South Carolina (the "Commission") on the petition of South Carolina Electric & Gas Company ("SCE&G" or the "Company") for an order approving an updated capital cost schedule and updated construction schedule for the construction of two 1,117 net megawatt ("MW") nuclear power units (the "Units") to be located at the V.C. Summer Nuclear Station near Jenkinsville, South Carolina. SCE&G filed the petition in this docket (the "Petition") on May 15, 2012, pursuant to S.C. Code Ann. § 58-33-270(E) (Supp. 2011). Under that provision of the Base Load Review Act (the "BLRA"), a utility "may petition the commission . . . for an order modifying any of the schedules, estimates, findings, class allocation factors, rate designs, or conditions that form part of any base load review order." S.C. Code Ann. § 58-33-270(E). Further, "[t]he commission shall grant the relief requested if, after a hearing, the commission finds . . . that the evidence of record justifies a finding that the changes are not the result of imprudence on the part of the utility." *Id.*

The Petition was preceded by a similar filing, dated February 29, 2012, in Docket No. 2012-90-E. The February 29, 2012 filing predated (i) the issuance of the Combined Operating License (the "COL") for the Units by the United States Nuclear Regulatory Commission (the "NRC"), (ii) the rescheduling of the substantial completion dates for the Units based on the COL issuance date, and (iii) the resolution of certain claims between SCE&G and the principal contractors for the Units, all of which are discussed in more detail below. By letter dated May 8, 2012, SCE&G withdrew the February 29, 2012 petition in Docket No. 2012-90-E. This allowed the Commission to establish a new hearing and pre-filing dates to allow the parties a full opportunity to review and conduct discovery on this new information. Accordingly, the May 15, 2012 Petition was filed in place of the February 29, 2012 petition.

A. Prior Base Load Review Act ("BLRA") Orders

In Order No. 2009-104(A), dated March 2, 2009, the Commission approved an initial capital cost schedule and construction schedule for the Units. As approved in that order, the capital cost for the Units was $4.5 billion in 2007 dollars. With forecasted escalation, this resulted in an estimated cost for the Units at completion of $6.3 billion in future dollars. The construction schedule approved in Order No. 2009-104(A) anticipated that Unit 2 would be completed by April 1, 2016, and the project as a whole would be completed by January 1, 2019. The South Carolina Energy Users Committee ("SCEUC") appealed Commission Order No. 2009-104(A) to the South Carolina Supreme Court.[1]

[1] An appeal from Order No. 2009-104(A) was also taken by Friends of the Earth, who oppose nuclear energy. In its review of that order, the South Carolina Supreme Court found that "based on the overwhelming amount of evidence in the record, the Commission's determination that SCE&G considered all forms of viable

In April 2009, SCE&G received its initial site-specific, integrated construction schedule from its principal contractors for the Units, Westinghouse Electric Company, LLC and the Shaw Group ("Westinghouse/Shaw"). At that time, SCE&G filed a proceeding under S.C. Code Ann. § 58-33-270(E) (an "update proceeding") for approval of the updated construction schedule for the project and an updated capital cost schedule which reflected the new schedule of cash flows associated with the updated construction schedule. The updated schedules did not alter the total estimated capital cost for the Units of $4.5 billion in 2007 dollars,[2] nor did they change the estimated completion dates for the Units. In Order No. 2010-12 dated January 21, 2010, the Commission approved the updated schedules.

On August 9, 2010, the South Carolina Supreme Court issued its decision in SCEUC's appeal of Order No. 2009-104(A), *South Carolina Energy Users Comm. v. South Carolina Pub. Serv. Comm'n*, 388 S.C. 486, 697 S.E.2d 587 (2010) (the "Opinion"). In the Opinion, the Court ruled that contingency costs that had not been itemized or designated to specific cost categories were not permitted as a part of approved capital cost schedules under the BLRA. The effect of this decision was to require the removal of $438.3 million in projected contingency costs from the capital cost schedules approved in Order No. 2009-104(A) and Order No. 2010-12.

In the Opinion, the Supreme Court acknowledged that S.C. Code Ann. § 58-33-270(E) allowed SCE&G to petition the Commission to update the capital cost schedule for the Units as SCE&G identifies and itemizes additional items of cost. The Court noted, "the General Assembly anticipated that construction costs could increase during the life of the project. Under

---

energy generation, and concluded that nuclear energy was the least costly alternative source, is supported by substantial evidence." *Friends of Earth v. Pub. Serv. Comm'n*, 387 S.C. 360, 369, 692 S.E.2d 910, 915 (2010).

[2] Unless otherwise noted, all dollar amounts used in this Order reflect the cost associated with SCE&G's 55% share of the ownership of the Units and are expressed in 2007 dollars.

§ 58-33-270(E), SCE&G may petition the Commission for an order modifying rate designs." *South Carolina Energy Users*, 697 S.E.2d at 592–93.

In response to the Opinion, SCE&G filed a petition in November 2010 for approval of an updated capital cost schedule. The Commission approved SCE&G's updated capital cost schedule in Order No. 2011-345, dated May 16, 2011. In that updated cost schedule, SCE&G—as required by the Opinion—removed its owner's contingency, i.e., costs that had not been itemized to specific capital cost categories. Where costs could be itemized, the Company requested Commission approval to include those additional cost items in the approved capital cost schedules. Because the amount of the newly itemized costs was less than the amount of the owner's contingency that was removed from the approved forecasts, the cost schedule approved in Order No. 2011-345 showed a reduction in the total estimated capital cost for the Units from $4.5 billion to $4.3 billion. (Tr. at 29.)

B. The Update Petition in This Docket

In the present docket, SCE&G has presented for review and approval additional capital cost and construction schedule updates. The cost updates fall into four categories: (i) Change Order No. 16 to the Engineering, Procurement and Construction Agreement (the "EPC Contract") for the Units; (ii) owner's cost ("Owner's Cost"); (iii) Transmission cost; and (iv) other change orders to the EPC Contract. (Tr. at 47-48.)

The first category includes costs associated with the February 2012 resolution of four claims made by Westinghouse/Shaw under the EPC Contract. These four claims were resolved as a package to clear the way for SCE&G to issue a full notice to proceed to Westinghouse/Shaw in April 2012. The claims in this category reflect (i) the additional cost of designing, permitting and constructing shield buildings for the Units with increased resistance to aircraft impacts, (ii) the additional costs in rescheduling the construction project as a result of the approximately nine-month delay in issuance of the COL, (iii) the costs associated with changing to the design of certain structural modules that will form part of the Units to increase the strength of steel used in them and to improve constructability, and (iv) the costs of responding to unanticipated rock conditions encountered for Unit 2. (Tr. at 47.) SCE&G and Westinghouse/Shaw documented the resolution of those four claims in Change Order No. 16 to the EPC Contract. That change order reflects $137.5 million of the amount of the requested adjustment in capital cost schedules requested in this proceeding.

In addition, the Petition states that since Order No. 2011-345 was issued, SCE&G has continued to review and revise its forecasts of the Owner's Cost that will be associated with hiring, training and deploying of staff for the project. That staff will oversee construction and testing of the Units and will also operate the Units when completed. It will also provide security both during and after construction. The costs associated with staffing the project include the cost of buildings, warehouse and other facilities to support both the project staff and the permanent staff as well as required furniture, supplies, janitorial services, building maintenance, and equipment, including information technologies systems. These costs are capital costs of the project, not annual costs, and will be incurred over the life of the project. The increased cost reflected in this Owner's Cost category totals $131.6 million of the requested update. (Tr. at 47-48.)

In addition, the Petition states that SCE&G has revised its estimates of the Transmission cost associated with the project by $7.9 million. These revisions are based on additional information as to design of the transmission facilities required to route power from the Units to customers and additional information concerning the nature and cost of the lines, substations, equipment upgrades and rights-of-way that will be required. Finally, the Petition reflects the costs associated with three other change orders to the EPC Contract that were negotiated with Westinghouse/Shaw and totaling $5.9 million. These three change orders were negotiated prior to Change Order No. 16 and dealt with difference scopes of work. (Tr. at 48.)

As shown in Chart A, below, taken together these requests total $283 million:

Chart A

REQUESTED UPDATES TO CONSTRUCTION COST SCHEDULES
($000)

Item		Cost
Change Order No. 16 (Shield Building, COL Delay, Modules, Rock Condition, etc.)	$	137,500
Owner's Cost	$	131,625
Transmission Cost	$	7,921
Other Change Orders (Cyber Security, Health Care, Wastewater Piping)	$	5,905
Total	**$**	**282,951**

These requested updates in cost raise the cost of the Units by $18 million, or 0.4%, over the $4.5 billion forecasted amount approved in the original BLRA order, Order No. 2009-104(A). (Tr. at 261.) However, escalation rates and rates for allowance for funds used during construction ("AFUDC") have been lower than anticipated when originally forecasted in 2008. (Tr. at 30.) As a result, the cost of the Units in future dollars is $5.8 billion which is $551 million, or approximately 8%, less than the $6.3 billion amount forecasted in 2009. (Tr. at 30.)

In the Petition, SCE&G also seeks approval of an updated construction schedule for the Units. This updated schedule delays the completion date of Unit 2 by 11 months to March 15, 2017, but advances the date for completion of the project as a whole by seven and one-half months to May 15, 2018. (Tr. at 212.)

The updated capital cost schedule was submitted as Hearing Exhibit No. 6 (CLW-1). The Public Version of that hearing exhibit is attached hereto as **Order Exhibit No. 1**. The updated construction schedule for the project was submitted as Hearing Exhibit No. 2 (SAB-3) and is attached hereto as **Order Exhibit No. 2.**

C. Notice and Interventions

In compliance with S.C. Code Ann. § 58-33-270(E), SCE&G timely provided notice of the Petition in this docket to the South Carolina Office of Regulatory Staff ("ORS"). ORS, pursuant to S.C. Code Ann § 58-4-10 (Supp. 2011), is automatically a party in this docket.

By letter dated May 24, 2012, the Commission's Clerk's office instructed the Company to publish by July 3, 2012, a Notice of Filing and Hearing in newspapers of general circulation in the area where SCE&G serves retail electric customers (the "Newspaper Notice"). The Clerk's office also instructed SCE&G to provide a copy of the Notice to its retail electric customers by U.S. mail or by electronic mail to customers who have agreed to receive notice by electronic mail (the "Customer Notice"). The Clerk's Office instructed SCE&G to provide proof of newspaper publication by July 18, 2012.

By letter dated May 29, 2012, SCE&G requested an extension of time to July 15, 2012, to provide the Customer Notice. By letter dated May 29, 2012, the Commission amended its notice requirements for both the Newspaper Notice and the Customer Notice. The revised publication schedule provided for both the Newspaper Notice and the Customer Notice to be accomplished by July 15, 2012, and for Commission receipt of proof of publication and certification of distribution on or before July 24, 2012. On July 13, 2012, the Company timely filed affidavits with the Commission demonstrating that the Newspaper Notice had been duly published in accordance with the Clerk's Office's instructions and certifying that a copy of the Customer Notice had been furnished to each affected customer.

Timely petitions to intervene in this docket were received from Pamela Greenlaw, the Sierra Club, SCEUC and Joseph Wojcicki. No other parties sought to intervene in this proceeding.

The petitions of Pamela Greenlaw, the Sierra Club, and SCEUC were not opposed by SCE&G. However, on May 29, 2012, SCE&G filed a Return in Opposition and Objection to the Petition to Intervene ("Return") of Mr. Joseph Wojcicki. On June 4, 2012, Mr. Wojcicki filed a reply to SCE&G's Return. By Order No. 2012-495, dated July 13, 2012, the Commission denied Mr. Wojcicki petition to intervene. On August 1, 2012, Mr. Wojcicki filed a motion asking the Commission to reconsider the denial of his petition to intervene. By Order No. 2012-622, dated August 15, 2012, the Commission denied Mr. Wojcicki's motion for reconsideration. Mr. Wojcicki did not appeal these orders, but did appear as a public witness to comment on matters at issue in this proceeding.

The Commission convened a public hearing on this matter on October 2-3, 2012, with the Honorable David A. Wright, Chairman, presiding. SCE&G was represented by K. Chad Burgess, Esq., Matthew W. Gissendanner, Esq., and Belton T. Zeigler, Esq. ORS was represented by Courtney Dare Edwards, Esq., Shannon Bowyer Hudson, Esq., and Jeffrey M. Nelson, Esq. The Sierra Club was represented by Robert Guild, Esq. and SCEUC was represented by Scott Elliott, Esq. Pamela Greenlaw proceeded *pro se*.

In support of the Petition, the Company presented the direct testimony of Kevin B. Marsh, Chairman and Chief Executive Officer of SCANA Corporation and SCE&G; Stephen A. Byrne, President for Generation and Transmission of SCE&G; David A. Lavigne, General

Manager, Operational Readiness for New Nuclear Deployment; Hubert C. Young, III, Manager of Transmission Planning for SCE&G; and Carlette L. Walker, Vice President for Nuclear Finance Administration.

ORS presented the direct testimony of Allyn H. Powell, Associate Program Manager in the Electric Department of ORS and Gary C. Jones, P.E., President of Jones Partners, Ltd.

The Sierra Club presented the direct testimony of Dr. Mark Cooper, Director of Energy and Director of Research at the Consumer Federation of America. SCEUC and Ms. Greenlaw presented no witnesses at the hearing.

In response to the testimony of Dr. Cooper, SCE&G presented the rebuttal testimony of Messrs. Marsh and Byrne, and Dr. Joseph M. Lynch, Manager of Resource Planning for SCE&G. The Sierra Club filed surrebuttal testimony of Dr. Cooper in response to SCE&G's rebuttal testimony. In response to Dr. Cooper's surrebuttal testimony, SCE&G filed a supplemental exhibit to Dr. Lynch's testimony providing the results of an economic study comparing the cost of completing the Units to the cost of pursuing a natural gas resource strategy. The Sierra Club conducted discovery on this comparative economic study prior to the hearing. At the hearing, the Sierra Club presented supplemental rebuttal testimony of Dr. Cooper challenging certain conclusions of Dr. Lynch's study.

D. Bill Issue Raised by Mr. Clements

On October 2, 2012, the Commission held a public night hearing in this proceeding at which 22 members of the public provided comments to the petition of SCE&G. At the public night hearing, Tom Clements, on behalf of the Alliance for Nuclear Accountability, informed the Commission of the billing practice of Georgia Power Company, who is constructing two AP1000 nuclear units in Georgia. As part of his public comments, Mr. Clements provided the

Commission with a copy of an electricity bill issued by Georgia Power Company that was included as part of the evidence of record and identified as Hearing Exhibit No. 3. The supplied bill contains a separate line item entitled “Nuclear Construction Cost Recovery.” Mr. Clements requests that as part of the ruling in this docket that the Commission issue an order instructing SCE&G to include this same information on SCE&G’s electricity bill. For the reasons set forth below, it is not necessary for SCE&G to include this information on its electricity bills.

The information that is required to be included on electricity bills is governed by 26 S.C. Code Ann. Regs. 103-339(2) (1976, as amended). The form of electricity bills has received careful consideration by the Commission and the General Assembly. The required information to be included on electricity bills provides a balance between providing customers with information necessary to ensure that each bill is calculated correctly while ensuring that the bill does not become overly complicated or confusing to customers. Each bill must include SCE&G’s contact information so that customers who have questions about their bill may raise them with Company representatives. Moreover, issuing an order in this proceeding is not the appropriate manner in which to implement a change 26 S.C. Code Ann. Regs. 103-339(2). Rather, the appropriate mechanism for such a change would be to initiate a rulemaking proceeding where the Commission receives public comment and the General Assembly has the requisite opportunity to review and approve the regulation.

Mr. Clements’ claim that SCE&G’s customers are uninformed regarding the cost of the Units is unfounded and not supported in fact. In every proceeding before the Commission regarding the Units, public notice and the opportunity to be heard is provided in the manner required by law and ensures public participation in and awareness of the process. At these public hearings, the public is encouraged to attend and comment. Additionally, for those persons who cannot attend the public hearing, the information presented during the hearing is available to the public for review at the Commission's offices as well as its website http://dms.psc.sc.gov/. We find that the current notice and hearing regime in place provides the public with sufficient and adequate notice of the proceedings regarding the Units and that the instant docket is not the appropriate proceeding to consider an alteration to regulations of the Commission. We also find that 26 S.C. Code Ann. Regs. 103-339(2) provides utility customers with sufficient information to be included on their electricity bill and therefore, decline to initiate a rulemaking proceeding on this matter.

II. STATUTORY STANDARDS AND REQUIRED FINDINGS

S.C. Code Ann. § 58-33-270(E) governs proceedings to update capital cost schedules and construction schedules that have been previously approved under the BLRA. Under this statute, the Commission must grant the relief requested, if after a hearing, the Commission finds that "as to the changes in the schedules, estimates, findings or conditions, that the evidence of record justifies a finding that the changes [in previously approved schedules] are not the result of imprudence on the part of the utility." S.C. Code Ann. § 58-33-270(E)(1) (Supp. 2011). In addition to S.C. Code Ann. § 58-33-270(E), the Commission is aware that under other provisions of the BLRA, determinations made in the initial BLRA order "may not be challenged or reopened in any subsequent proceeding." S.C. Code Ann. § 58-33-275(B). In this regard, "[c]hanges in fuel cost will not to be considered in conducting any evaluation under this section." S.C. Code Ann. § 58-33-275(D).

A. The Sierra Club's Argument

Through the testimony of Dr. Cooper, the Sierra Club argues that the Commission should deny SCE&G's Petition and find that the additional costs presented by SCE&G for approval in this update proceeding are imprudent. (Tr. at 956.) Specifically, the Sierra Club asserts that because natural gas prices have fallen considerably since 2009, and because energy conservation and alternative generation sources may be becoming more cost competitive, the Commission should find that it is no longer prudent for SCE&G to continue construction and complete the Units and consequently, that the additional costs are likewise imprudent. (Tr. at 962.) For all practical purposes, the Sierra Club's argument is tantamount to a request that the Commission issue an order instructing SCE&G to terminate the project.[3]

B. Prior Commission Determinations

Although Dr. Cooper discusses alternative generation and energy efficiency in his testimony, the specific base load generation resource that Dr. Cooper seeks to demonstrate to be preferable to nuclear generation is combined-cycle natural gas generation. (Tr. at 962.) This is not the first time that the Commission has considered the relative merits of a natural gas resource strategy compared to a nuclear resource strategy. In the original BLRA proceeding, Docket No. 2008-196-E, the principal focus of the testimony in support of the Company's application and in opposition to it was the comparison of nuclear and natural gas resource strategies. The studies and other evidence presented in Docket No. 2008-196-E specifically compared the risks and benefits of a nuclear resource strategy to a combined cycle natural gas resource strategy. Those studies considered a number of possible scenarios, including the possibility of lower than anticipated natural gas prices in the future. The testimony presented by Dr. Cooper in this

[3] Dr. Cooper did not assert that any fundamental flaw exists or has been discovered in the AP1000 units, in the Jenkinsville site, or in nuclear power generally. To the contrary, the Commission finds that the evidence of record overwhelmingly supports the conclusion that nuclear generation continues to be a safe, practical and efficient source of electrical power and that construction of the Units is proceeding in a safe, efficient and satisfactory manner. Most of the major challenges identified in the early stages of the engineering, procurement, construction and permitting for the Units have been overcome. (Tr. at 32.) As to safety and environmental concerns, the design of the Units and the Jenkinsville site have recently passed rigorous reviews by the NRC and other state and federal permitting agencies. (Tr. at 148.) In short, the project is progressing well and its risk profile is much lower than it was in 2008 and 2009.

proceeding is based on the data and analysis presented by SCE&G in Docket No. 2008-196-E. (Tr. at 962-63.) Through sensitivity studies and other approaches, Dr. Cooper has sought to 'update' the 2008 studies by including new data related to gas prices and other factors.

In Order No. 2009-104(A), the Commission carefully reviewed the merits of the natural gas resource strategy compared to the nuclear resource strategy. The Commission entered detailed and specific findings supporting SCE&G's decision to construct the Units rather than choosing to rely on combined cycle natural gas units to meet its base load generation needs. See Order No. 2009-104(A). In its review of that order, the South Carolina Supreme Court found that "based on the overwhelming amount of evidence in the record, the Commission's determination that SCE&G considered all forms of viable energy generation, and concluded that nuclear energy was the least costly alternative source, is supported by substantial evidence." *Friends of Earth v. Pub. Serv. Comm'n*, 387 S.C. 360, 369, 692 S.E.2d 910, 915 (2010).

C. Policies and Procedures and Key Provisions of the BLRA

The Sierra Club's arguments raise important questions about practice under the BLRA. The Sierra Club argues that the issue of whether the Commission should approve increasing capital forecasts for the Units requires the Commission to determine whether it is prudent to continue the construction of the Units at all. (Tr. at 953.) Therefore, as a condition of approval of the updated capital cost schedules at issue here, the Sierra Club ultimately seeks to reopen the issue of whether nuclear generating resources remain the appropriate choice for SCE&G.

For its part, SCE&G asserts that the arguments and evidence presented by the Sierra Club in this proceeding constitute an attempt to reopen the determinations made in Order No. 2009-104(A) concerning the appropriateness of choosing a nuclear generation resource strategy as compared to a natural gas resource strategy, which on its face appears to be contrary to S.C.

Code Ann. § 58-33-275(B). SCE&G takes the position that under S.C. Code Ann. § 58-33-270(E), the operative question before the Commission in an update proceeding is whether "as to the ***changes*** in the schedules [presented by SCE&G] . . . the evidence of record justifies a finding that the ***changes*** are not the result of imprudence on the part of the utility." S.C. Code Ann. § 58-33-270(E) (Supp. 2011) (emphasis supplied). That is, SCE&G contends that the plain language of the statute focuses the Commission's review on the prudence of the specific changes to the cost and construction schedules that are being proposed in this docket. (Tr. at 76.)

In weighing these arguments, the Commission notes that the BLRA was intended to cure a specific problem under the prior statutory and regulatory structure. Before adoption of the BLRA, a utility's decision to build a base load generating plant was subject to relitigation if parties brought prudency challenges after the utility had committed to major construction work on the plant. The possibility of prudency challenges while construction was underway increased the risks of these projects as well as the costs and difficulty of financing them. In response, the General Assembly sought to mitigate such uncertainty by providing for a comprehensive, fully litigated and binding prudency review before major construction of a base load generating facility begins. The BLRA order related to the Units, Order No. 2009-104(A), is the result of such a process. It involved weeks of hearings, over 20 witnesses, a transcript that is more than a thousand pages long and rulings that have been the subject of two appeals to the South Carolina Supreme Court.

In support of the approach taken in the BLRA, S.C. Code Ann. § 58-33-275(A) establishes the final and binding nature of BLRA orders as a matter of law. Furthermore, S.C. Code Ann. § 58-33-275(B) states that the determinations made in such orders "may not be challenged or reopened in any subsequent proceeding." Finally, S.C. Code Ann. § 58-33-275(D) recognizes the specific danger that would be posed to this regulatory scheme if changes in fuel costs could result in a reassessment of the prudency of base load units during construction. Under S.C. Code Ann. § 58-33-275(D), "[c]hanges in fuel costs will not be considered in conducting any evaluation under this section." Changes in fuel costs are the principal factual foundation of the Sierra Club's position in this matter.

The approach to the BLRA that is proposed by the Sierra Club would inject prudency challenges back into the process for building base load generating facilities whenever an update proceeding is required. The cost schedules approved under the BLRA do not include owner's contingency, and for that reason, update proceedings will now be necessary to review and approve even minor adjustments in cost forecasts. See *South Carolina Energy Users Comm. v. South Carolina Pub. Serv. Comm'n*, 388 S.C. 486, 697 S.E.2d 587 (2010). Update proceedings are likely to be a routine part of administering BLRA projects going forward (including future projects proposed by other electric utilities), such that under the Sierra Club's argument, the prudence of the decision to build the plant will be open to repeated relitigation during the construction period if a utility seeks to preserve the benefits of the BLRA for its project. Reopening the initial prudency determinations each time a utility is required to make an update filing would create an outcome that the BLRA was intended to prevent and would defeat the principal legislative purpose in adopting the statute.

The Commission need not decide these issues in this proceeding because the record in this proceeding provides the Commission with sufficient evidence on which to examine and evaluate the positions of SCE&G and the Sierra Club on the factual issue of whether continuing with construction of the Units is prudent and whether the additional costs are prudent. Based on the evidence of record before us, the Commission concludes that the construction of the Units should continue and that the additional costs are not the result of imprudence on the part of SCE&G.

III. REVIEW OF THE EVIDENCE AND EVIDENTIARY CONCLUSIONS

The Commission has reviewed the facts and evidence of record and reaches the following conclusions:

A. Prudency of Completing the Units

The factual record concerning the Sierra Club's challenge to the prudency of completing the Units is contained in the direct and surrebuttal testimony, as supplemented at the hearing, of its witness Dr. Cooper, and the responses to it in the rebuttal testimony by Mr. Marsh, Mr. Byrne and Dr. Lynch, and the comparative economic analysis conducted by Dr. Lynch, Exhibit No. 9 (JML-4).

1. Dr. Cooper's Factor Analysis

Dr. Cooper's analysis of the prudency of continuing to construct the Units focused on the comparative cost of natural gas generation and nuclear generation given current natural gas prices. (Tr. at 962.) Dr. Cooper based his study on the data and analysis presented by Dr. Lynch in Docket No. 2008-196-E (the "2008 Studies"). (Tr. at 963; Hr'g Ex. 10 (MNC-4)). He sought to recalculate its results based on changes in one factor, specifically, the recent decline in natural gas prices.

In the 2008 Studies, Dr. Lynch showed that at the baseline natural gas price forecast, the advantage of the nuclear resource strategy over the natural gas resource strategy was $15 million dollars per year levelized over forty years. (Tr. at 963.) In other words, the nuclear resource strategy was the least costly resource and one scenario quantified that this lower cost resulted in levelized savings to customers of $15 million per year. *See* Commission Order No 2009-104(A) and *Friends of Earth v. Pub. Serv. Comm'n,* 387 S.C. 360, 369, 692 S.E.2d 910, 915 (2010). Dr. Lynch also provided a sensitivity analysis, which demonstrated that if natural gas prices were higher than forecasted by 25%, the comparative benefit of the nuclear resource strategy increased over the gas resource strategy from $15 million to $53.4 million per year. (Tr. at 963.)

Dr. Cooper determined that in mid-2012, the current Energy Information Administration ("EIA") natural gas cost forecasts were 62% below the base line forecast used in Dr. Lynch's 2008 Studies. (*Id.*) Based on the relationship between these numbers, he computed that a 62% decline in natural gas price forecasts would cause a shift of approximately $132 million in the relative economics of the nuclear and natural gas resource strategies as calculated in the 2008 Studies. (*Id.*) Since the nuclear resource strategy started with a $15 million advantage, Dr. Cooper reduced the $132 million savings he calculated by that amount. This resulted in a calculation showing a net advantage to the natural gas resource strategy of $15 million. (*Id.*)

Dr. Cooper then increased his estimated savings from natural gas by assuming that there would be no cost associated with carbon ("CO_2") emissions. Dr. Lynch's 2008 studies had shown that assuming zero CO_2 cost, the natural gas resource strategy had an advantage over the nuclear resource strategy of $87 million per year. (Tr. at 964.) Dr. Cooper added this amount to his $115 million calculation to conclude that the levelized cost of the natural gas resource strategy over the nuclear resource strategy was in excess of $200 million. (*Id.*) He then multiplied this amount by 40 to reflect the forty-year planning horizon for Dr. Lynch's study. Based on this calculation, he determined that the natural gas resource strategy had a cumulative $8 billion advantage over nuclear.[4] (Tr. at 964.) In summary and according to Dr. Cooper, the natural gas resource strategy is now the least costly resource.

---

[4] Dr. Cooper claimed that SCE&G did not factor certain risks into its original cost projections that were approved under the BLRA even though these risks should have been evident at that time. (Tr. at 972.) The risks

2. Dr. Lynch's Alternative Factor Analysis

SCE&G's rebuttal testimony challenged Dr. Cooper's conclusions on several points. First, Dr. Lynch prepared an alternative analysis focusing on two factors related to the current cost of completing the Units. (Tr. at 903-04.) One factor was the reduction in the cost of the Units due to lower escalation and AFUDC rates than were anticipated in 2008. Lower escalation and AFUDC costs have reduced the forecasted cost of the Units in future dollars by $551 million. The other factor Dr. Lynch analyzed was that 25% of the current costs of the Units have already been spent and only 75% is required to be spent to complete them. In comparing the cost of completing the Units versus switching to a natural gas resource strategy, Dr. Lynch pointed out, and Dr. Cooper agreed, that the analysis must take into account that a substantial part of the cost of building the Units has been spent. (Tr. at 977, 890, 904.)

In his rebuttal testimony, Dr. Lynch quantified the impact of these two factors using a standard tool employed in utility planning analyses, the levelized carrying cost for investment. This represents the annual cost that must be charged to customers for each dollar spent on a utility investment to fund depreciation, taxes, the cost of capital (debt and equity) and insurance related to that investment. In this case, Dr. Lynch computed the specific carrying cost for

---

that he believes SCE&G should have originally factored into its cost projections include difficulties in staffing the Units, supply chain issues, delays in regulatory approval, and the possibility that regulations would change during the construction of the Units. (Tr. at 970-71.) According to Dr. Cooper, SCE&G should have been aware of these risks and factored the cost associated with them into the original cost projections. (Tr. at 972.) He asserts that the failure of SCE&G to consider these risks amounted to its presenting the Commission with a "low ball estimate" of the cost of the Units. Had the Commission been presented with the actual cost of the Units, including the $450 million that he claims amount to cost overruns, it may have arrived at a different decision regarding their prudency. (Tr. at 972.)

The Company rebutted these claims in the testimony of Mr. Byrne. Mr. Byrne points out that the cost forecasts and the EPC Contract were independently audited by consulting firms retained by ORS. (Tr. at 269.) The experts within those consulting firms had extensive experience with forecasting costs related to major electric generation projects, including nuclear projects. (*Id.*) Those experts would also have been familiar with the risks inherent in nuclear construction. These independent reviews of the cost forecasts and the EPC Contract found nothing to indicate that SCE&G's cost estimates were inaccurate. The Commission finds Mr. Byrne's testimony credible and does not find that the evidence on the record supports the "low ball" allegation.

investment in the Units taking into account the items mentioned above. He did so on a levelized basis over the 40-year planning horizon. As Dr. Lynch testified, the levelized carrying cost factor for investment in the Units is 16%, *i.e.,* for each dollar invested, SCE&G must collect $0.16 per year over the planning horizon. (Tr. at 903.) Applying this factor to the $551 million reduction in the cost of the Units, the annualized savings of the nuclear strategy increases by $88 million ($551 million * 0.16%). (Tr. at 904.)

Dr. Lynch also testified that because, as of June 30, 2012, approximately 25% of the currently forecasted cost of the Units has been spent, the cost to complete the Units is reduced by approximately $1.4 billion. (Tr. at 892.) As a result, for planning purposes, the levelized going-forward cost of pursuing the nuclear strategy has been reduced by the additional amount of $230 million per year, which is the carrying cost that would be incurred on that $1.4 billion.[5] Accordingly, Dr. Lynch testified that these two factors alone reduced the cost of the nuclear strategy by a total of $318 million on an annualized basis. This amount far exceeds the amounts that Dr. Cooper calculated to be the savings that result either from low natural gas cost forecasts alone or from the low natural gas and zero CO_2 costs scenarios combined. (Tr. at 890-92.)

Dr. Lynch further testified that in planning studies, the appropriate way to reflect levelized savings as a lump sum is through a present value calculation, not by simply multiplying the levelized annual cost by the number of years in the study as Dr. Cooper calculated. (Tr. at 892.) Calculating the net present values of the savings discussed above, Dr. Lynch presented a chart, which is produced below, showing the relative impact of the factors identified in the comparative analyses presented in 2008.[6]

[5] $5,762 million * 0.16 * 0.25, where $5,762 million is the current cost of the Units, 25% is the amount that has been spent and 16% is the levelized carrying cost of nuclear investment.

[6] On page 6 of Dr. Cooper's surrebuttal testimony, he alleges that the Company has "double discounted [his] calculation of natural gas savings" without providing sufficient additional detail to validate this claim. (Tr. at

Chart B

Dr. Cooper's Adjustments to Natural Gas Strategy Costs (reduced costs, in millions)		SCE&G's Adjustments to Nuclear Strategy Costs (reduced costs, in millions)	
Low Gas Cost Alone			
Levelized Per Year	$115		
Accumulated	$4,000		
Present Value	$1,400		
Low Gas Cost & No CO_2 Cost		**Going-Forward Cost**	
Levelized Per Year	$200	Levelized Per Year	$318
Accumulated	$8,000	Accumulated	Not Computed
Present Value	**$2,400**	**Present Value**	**$3,900**

(Tr. at 910.)

3. Natural Gas Price Volatility

Dr. Lynch also faulted Dr. Cooper's analysis on the basis of its reliance on natural gas price forecasts that are inherently unreliable:

> Planners, if they are prudent, do not put much confidence in anyone's projection of natural gas prices. That is why almost all resource planning studies involve scenario planning and sensitivity analysis around the most uncertain drivers of cost. The price of fossil fuels is one of the most volatile and uncertain drivers of energy costs.

(Tr. at 898.) Dr. Lynch provided data from EIA showing that EIA acknowledges that its forecasts are almost always in error, whether too high or too low. In addition, EIA has computed the 95% confidence interval around its forecast of gas prices through 2013. Within that confidence interval, natural gas prices could be as high as $7.76 per MMBTU on December 31, 2013, or as low as $2.11, with the expected price being $3.63. This means that in mid-2012, EIA

981.) From the Commission's review of the figures presented by the Company, the Commission finds that the calculations provided by SCE&G appear to be correctly computed and do not involve double counting. Based on the information provided by Dr. Cooper, the Commission is constrained to find his argument without factual basis or merit.

recognized that by December 2013, there was an equal probability of natural gas prices being 214% higher than the forecasted price as there was of them being 42% lower. (Tr. at 898-99.)

As Mr. Marsh testified, "[i]f there is anything that I have learned in my more than 30 years of experience in this industry, it is that current gas price forecasts—whatever they are—will change. The projections on which Dr. Cooper relies were different four years ago, and in all likelihood will be different four years from now." (Tr. at 86.)

Dr. Lynch further identified a number of "forces at work in the economy that could cause today's forecasts of future gas prices to prove inaccurate." (Tr. at 901.) Those factors include the increasing substitution of natural gas for coal as an electric generation fuel, increased exports of liquefied natural gas in response to a wide disparity between domestic U.S. natural gas prices and international energy prices, and the expansion in the United States of industries that use a high volume of natural gas for fuel and feedstock. (Tr. at 900.)

Natural gas prices are low today because of a new technology known as hydrological fracturing, or fracking. (Tr. at 899.) Over the past two years, fracking has opened up an abundance of new gas supply that has driven domestic natural gas prices down to levels that are now much lower than comparable prices internationally.

Fracking, however, is under increasing environmental attack by certain special interest groups, including the Sierra Club, that wish to limit its use. (Tr. at 78, 901-02.) In addition, recent Environmental Protection Administration ("EPA") regulations related to CO_2 emissions have made it economically impossible to build coal plants to meet the demand for electricity. (Tr. at 901.) Dr. Lynch testified that apart from nuclear "there is now only one type of dispatchable base load/intermediate load generation resource that can be built in most of the United States. That is combined-cycle gas generation." (Tr. at 902.) This development will "create the need for new pipeline capacity to deliver gas in the required volumes, which involves construction and permitting costs and risks, which can lead to higher costs. Of course, if you burn gas, you emit carbon, so another risk of gas generation is the risk that CO_2 costs will be imposed directly on gas as a fuel." (Tr. at 901.)

Based on the foregoing, Dr. Lynch testified that "there is a great deal of uncertainty in natural gas prices and in their projection. Prudent resource planning decisions cannot be made based on a single scenario of natural gas price projections." (Tr. at 902.) Dr. Lynch concluded:

> I have much more confidence in the $318 million adjustment [that Dr. Lynch calculated] than the $115 million [in savings that Dr. Cooper calculated]. More than two-thirds of the cost left to be spent under the EPC contract are fixed or subject to fixed escalation rates. Of course, the 25% of the cost of the Units that has already been spent is fully known and measurable. On the other hand, I have already discussed the volatility and uncertainty of prices in the natural gas market. The $115 million adjustment to the natural gas generation strategy is based on an assumption of low gas prices over the next 40 years which is very uncertain. All indications are that the uncertainty of the gas price forecast is much greater that the uncertainty surrounding the cost of completing the construction cost of the Units.

(Tr. at 906.)

4. Mitigating Risk Through a Balanced Generation Portfolio

SCE&G's witnesses also criticized Dr. Cooper's approach for relying entirely on a single factor/single scenario cost analysis:

> Experienced planners formulate generation plans by evaluating multiple sets of price and regulatory assumptions that encompass a broad range of possible conditions that the system may encounter over the 40-year planning horizon. No one scenario dictates the selection decision, as Dr. Cooper's testimony would suggest. Instead, the modeling results for many different scenarios inform the evaluation. The goal is to determine what generation choices lead to the most flexible, resilient and robust mix of generation resources. The mix we seek is the one that can perform best under the widest range of possible market, operating and regulatory conditions, and that preserves for SCE&G and its customers the best options for dealing with future uncertainty.

(Tr. at 82.) The reason for this approach is that "fossil fuel markets, and now environmental policies as to fossil fuel, are inherently volatile and cannot be predicted with certainty. Market conditions and regulatory requirements will change in ways that cannot be predicted over the 40-year plus period that fossil plants will be in service." (Tr. at 80.) Given that volatility:

> [i]t is a fundamental mistake to believe that sound base load planning decisions can be made simply by modeling outcomes based upon current projections of future fossil fuel costs or regulatory conditions. Such one-dimensional analysis does not take into consideration the dynamic energy markets in which we operate or our inability to know with certainty what market, regulatory and operating conditions will be decades in the future. In this context, one-dimensional analyses are dangerous and expose our customers to risk.

(Tr. at 80.) Mr. Marsh testified that analytical modeling is "not the end of the resource selection process, but the beginning." (Tr. at 84.) The question to be answered is: "Which type of generation would contribute to a generation portfolio that could best respond to the widest range of potential conditions in fuel markets, operating conditions and environmental costs over the coming decades and give SCE&G the most options to respond to unanticipated conditions in the future?" (Tr. at 84-85.) That decision is not determined by any "single analysis or set of assumptions as to future natural gas costs, operating conditions or environmental costs . . . ." Tr. at 85.) Instead, it is "informed by information about how the different configurations of the system would perform across multiple sets of assumptions, combined with the business judgment and the collective wisdom of an experienced team of planners, engineers and executives." (Tr. at 85.)

Referring to the initial decision to construct the Units, Mr. Marsh stated:

> We concluded then, and still believe today, that adding nuclear generation creates a system that can perform best in the widest range of conditions over the coming decades. As I mentioned in my direct testimony in this docket, by adding nuclear generation, our generation mix in 2019 will be 27% coal, 28% natural gas, 31% nuclear and 14% hydro/biomass. This will give us the flexibility to switch between coal and gas generation as conditions warrant. It will mean that in 2019,

> we will have reduced our carbon emissions by 54% compared to their levels in 2005, giving us a secure position if carbon taxes, cap and trade systems, or other regulatory mechanisms impose costs on carbon emissions. Our balanced generation portfolio will also mean that as we go forward from 2019, we would have the option to add additional natural gas-fired generation to our system without fear of becoming overly reliant on natural gas as a fuel. We can also add resources like solar, wind or DSM where feasible knowing that standing behind them is a secure foundation of reliable generation.

(Tr. at 85.) By contrast, "[i]f the Commission were to accept Dr. Cooper's recommendation, then in 2019, SCE&G's customers would be relying on a generating system that generates 47% of its electricity from natural gas, which the Sierra Club opposes, and 76% from fossil fuels, which they also oppose."[7] (Tr. at 78.)

Mr. Marsh further testified, "More than 660,000 customers depend on SCE&G for reliable, efficient electric service . . . . Making base load selection decisions on one-dimensional analyses like Dr. Cooper's is not how SCE&G can best fulfill its future service obligations to its customers." (Tr. at 80-81.)

5. Dr. Lynch's Comparative Economic Study

In his surrebuttal testimony, Dr. Cooper insisted that "the Commission needs a new economic analysis of the going forward costs to ascertain whether continuing the project is prudent." (Tr. at 979.) In response, on September 27, 2012, SCE&G provided to the parties Dr. Lynch's "Comparative Economic Analysis of Completing Nuclear Construction or Pursuing a Natural Gas Resource Strategy" (the "2012 Study"). It was entered into evidence, without objection, as a supplemental exhibit to the rebuttal testimony of Dr. Lynch (Hr'g Ex. 9 (JML-4)). After the 2012 Study was filed, the Sierra Club, on September 28, 2012, served SCE&G with

---

7 *Fossil fuels have no part in America's energy future—coal, oil and natural gas are literally poisoning us. The emergence of natural gas as a significant part of our energy mix is particularly frightening because it dangerously postpones investment in clean energy at a time when we should be doubling down on wind, solar and energy efficiency.*

Beyond Natural Gas, SIERRA CLUB, http://content.sierraclub.org/naturalgas (last visited August 23, 2012).

discovery demands related to it. SCE&G responded to those discovery demands on September 30, 2012, in advance of the hearing.

The 2012 Study presented multi-factor scenario analyses that used the same models and approach that were used in performing the 2008 Studies. In the 2012 Study, relevant inputs were updated to reflect the current cost of completing the Units, the current capital cost of combined cycle generation, and current natural gas price forecasts based on data provided by the economic forecasting firm which SCE&G retained for that purpose (these forecasts of natural gas prices were somewhat lower than Dr. Cooper's EIA forecasts of natural gas prices). The 2012 Study was also based on current nuclear fuel cost forecasts, the Company's current cost of capital and capital structure, new substantial completion dates for the Units, the current value of production tax credits related to the Units, and current forecasts of future electric loads as used in preparing SCE&G's Integrated Resource Plan as submitted to the Commission each year. In preparing the 2012 Study, SCE&G also calculated the estimated cost of terminating the EPC Contract and subcontracts under it, and decommissioning the site. As an offset to those costs, SCE&G estimated the value it would expect to receive from selling to third parties the equipment, material and work in progress on hand. The cost to SCE&G of cancellation, net of sales and salvage, was $543 million.[8] (Hr'g Ex. 9.)

The 2012 Study compared the economics of completing the Units as planned in 2017 and 2018 versus abandoning construction and instead constructing two 614 MW combined-cycle gas units, providing the net generating capacity identical to the nuclear Units. To ensure comparability in the analysis, the 2012 Study assumed that the combined-cycle gas units would come on-line on the same dates as the nuclear Units being replaced. (*Id.* at 1.)

---

[8] The total amount was $988 million. SCE&G would seek to recover 45% of that amount from Santee Cooper under their agreements concerning joint ownership of the project.

As Dr. Lynch explains, the 2012 Study assumed that normal payments under the EPC Contract would cease on January 1, 2013. The amount spent at that time would be approximately $2 billion. Under the natural gas resource strategy, the $2 billion spent on the abandoned nuclear construction and the $543 million in net abandonment costs are recovered over 40 years under the terms of S.C. Code Ann. § 58-33-280(K) (Supp. 2011). (*Id.* at 2.) The nuclear resource strategy reflects the full cost of the Units of $5.8 billion being recovered over the life of the plants.

The 2012 Study compares the revenue requirements of the nuclear and natural gas resource strategies under 27 different scenarios applying three different sets of variables. One set of variables was based upon three natural gas price forecasts: the SCE&G forecast; the SCE&G forecast plus 50%; and the SCE&G forecast plus 100%. The study considered three scenarios concerning costs related to carbon emissions effective in 2017: no cost per ton of CO_2; $15 per ton of CO_2; and $30 per ton of CO_2. Scenarios were run to test the sensitivity of the analysis to variations in future electric demands. The study considered high load, base load and low load forecasts. The high electric load forecast was 5% above the base electric load forecast, and the low electric load forecast was 5% below. (*Id.* at 5-8.)

The 2012 Study demonstrated that in each of the 27 scenarios, completing the Units represented the lower cost alternative than switching to a natural gas resource strategy. In the base electric load scenario,[9] the savings varied from $26 million per year, applying base gas prices and no cost for CO_2 emissions, to $407 million per year in the high gas scenario and a $30 per ton CO_2 price. (*Id.* at 9.)

[9] As Dr. Lynch testified, the 2012 Study results demonstrated that the analysis was not materially sensitive to what electric load forecast assumptions were made. The variation between the electric load scenarios was minimal.

Chart C

Benefit of Nuclear Strategy over the Gas Strategy
Base Electric Load Scenario
Levelized Present Worth of Change in Revenue Requirements
Over 40 Years ($MM)

	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO2 Price	$26	$144	$262
$15 CO2 Price	$102	$215	$335
$30 CO2 Price	$175	$290	$407

The 2012 Study found that the most reasonable scenario for planning purposes was the scenario applying base electric load, 50% higher gas prices and a $30 per ton CO_2 price. Dr. Lynch found this scenario to be the most reasonable for two reasons. First, the moderately higher gas price reflected the fact that the SCE&G forecast was very low when compared to the EIA forecast, and the greater probability is that future gas prices will be higher than forecasted, not lower. The choice of the $30 per ton CO_2 price reflected that this price is lower than the price used by the Federal Government in assessing the social cost of CO_2 emissions when evaluating the net impact of new regulatory action. (Tr. at 4-5.) In addition, costs substantially below that level would be insufficient to drive behavior in a way that would effectively limit emissions. In the base electric load, 50% higher gas prices and $30 per ton CO_2 price scenario, the savings from completing the Units and not switching to a gas natural resource strategy is $290 million per year.

6. Evaluation and Conclusions

The Commission finds that the evidence presented by SCE&G amply establishes the prudency of continued investment in the project. The Commission finds that Dr. Lynch's initial factor analysis and the subsequent 2012 Study are both credible and reliable evidence sufficient to support prudency of the project in all respects and meet all relevant and material points raised in Dr. Cooper's testimony. The Commission agrees that for the reasons stated by Dr. Lynch, the most reasonable and credible assessment of the cost benefits of the nuclear strategy as compared to the natural gas resource strategy is the scenario applying base electric load forecast, 50% higher gas prices and $30 per ton CO_2 price, which Dr. Lynch chose as the most reasonable to adopt for planning purposes. (2012 Study at 7.) That scenario demonstrates that the most reasonable and reliable estimate of the price advantage of the nuclear strategy as compared to the natural gas resource strategy is a levelized savings of $290 million per year over 40 years.

The Commission further finds, as Dr. Lynch testified (Tr. at 930-33), that any reasonably foreseeable changes in the capital cost of the Units would not change the outcome of his analysis[10] or the conclusion that the nuclear resource strategy remains the most beneficial and prudent strategy for the Company under current gas price forecasts and other conditions. The Commission finds, as Mr. Marsh testified (Tr. at 82-83), that decisions concerning the construction of new base load generation plants should be made with the goal of creating a diverse and balanced generation portfolio that can perform well under multiple conditions concerning fuel costs and environmental regulations. For that reason, in establishing prudency and making siting decisions for base load units, undue weight should not be placed on any single scenario or analysis related to fuel prices or environmental costs.

In addition, the Commission finds that prudency in base load selection decisions should be assessed recognizing that the benefits of fuel diversity and the flexibility to respond to future environmental regulations are important factors to be considered. The evidence presented in this docket demonstrate that additional nuclear generation will bring considerable benefits of this type to SCE&G's generation portfolio and that those benefits exist across a diverse range of possible

[10] In rough terms, if a decrease in the capital cost of the Units of $551 million results in an $88 million change in the levelized annual savings, then all other things being equal, it would take an increase in the Units' capital cost of over $1.8 billion to offset the $290 million in benefits Dr. Lynch calculated. (Tr. at 904).

scenarios for fuel costs and environmental regulations. Furthermore, the record here amply demonstrates that the potential risks of relying on natural gas price forecasts remaining as low as they are today are significant. For all these reasons, the Commission finds that the Company has made an affirmative and entirely sufficient demonstration of the prudency of its nuclear construction program. (*See*, *e.g.*, Tr. at 899.)

B. Update to BLRA Approved Cost Schedules

In its Petition, SCE&G asked for updates to its cost schedules in four major categories, each of which is discussed below:

1. Change Order No. 16

The Company is seeking Commission approval of the costs associated with Change Order No. 16, which represents $137.5 million, or slightly less than half of the total change in costs requested in this proceeding. (Tr. at 187, 195.)

(a) Shield Building Redesign

The shield building design for the Westinghouse AP1000 Unit was originally approved in a Safety Evaluation Report by the NRC in 2004. It incorporated reinforced steel reinforced concrete walls and a steel reinforced concrete roof. (Tr. 1056-59.) At the time that the EPC Contract was executed the NRC had issued a draft rule for comment that would require shield buildings to be designed with greater resistance to aircraft impacts than had been required when the AP1000 reactor received it design certification in 2004. However, at the time the EPC Contract was executed, the draft rule and its requirements had not been finalized or issued. (Tr. at 192.)

To comply with the requirements of the rule as proposed, Westinghouse began work to redesign the AP1000 shield building. Westinghouse originally planned to increase the strength of the design by increasing the thickness of the shield building's reinforced steel concrete walls and roof. However, the initial work showed that meeting the requirements of the rule would require increasing the thickness of the shield building walls to an extent that would decrease the interior volume of the building to an impractical degree. Westinghouse's solution was to select a design that included a continuous shell of welded steel plates on the inside and outside of the shield building. This is referred to as a "steel composite design." Concrete would then be poured between the walls of the steel plates. The inner and outer steel shells provide strength and durability to the concrete and shear strength via metal studs, called Nelson Studs, that are anchored to the inner and outer steel shells and protrude into the space where the concrete is poured. (Tr. at 192-93.)

In addition, the new design required revisions to the structural connection between the floor support for the building (the "base-mat") and the shield building walls, as well as between the shield building and the auxiliary building. Design changes were also needed for the air inlets and the tension ring which are located at the transition between the shield building wall and the roof. (Tr. at 193.)

Steel composite design of this sort had been used in other countries, but had not been used for similar applications in the United States. For that reason, design codes certifying the strength and performance of this type of construction had not been issued in this country. As a result, the NRC required Westinghouse to conduct extensive testing to verify the performance of this design. The NRC required repeated iterations of testing before certifying the design. Difficulty with the testing and certification of this design was an important factor in Westinghouse's inability to obtain approval of the revised design within the anticipated schedule. (Tr. at 196.)

In 2011, Westinghouse/Shaw asserted a claim under the EPC Contract for the additional costs associated with the designing, testing and construction of the new shield building design. Westinghouse/Shaw did so based on a provision of the EPC Contract that provides for change orders where cost increases are due to "uncontrollable circumstances." Under the EPC Contract, "uncontrollable circumstances" can mean, among other things, an order or other action by a governmental authority that is not the result of the negligent or willful acts of the party claiming uncontrollable circumstances. Westinghouse/Shaw claimed that the aircraft impact rule, and its interpretation by the NRC, was a governmental order or action that fell within the definition of an uncontrollable circumstances. SCE&G challenged this claim. (Tr. at 194.)

(b) COL Delay

When the EPC Contract was executed, SCE&G and Westinghouse/Shaw anticipated that the NRC would issue the COL for the Units in mid-2011, slightly more than three years after the initial COL application was filed. As Mr. Byrne testified, that expectation was based on information provided to SCE&G and the public by the NRC.[11] This information was accepted by the parties to the EPC Contract as a reasonable basis for establishing the construction and equipment delivery schedules included in the EPC Contract. At that time, the AP1000 design had been approved for several years. The shield building redesign related to aircraft impact

[11] After the close of evidence at the hearing in this matter, Intervenor Pamela Greenlaw, as a *pro se* litigant, sought to compel SCE&G to provide additional discovery responses related to the establishment in the EPC Contract of the date of mid-2011 as the anticipated date for COL issuance. At the Commission's request that she follow up with her oral request in writing. Ms. Greenlaw served a "motion to compel" seeking the above-detailed information on October 16, 2012, fourteen days after the conclusion of the hearing in this proceeding. In that document, she sought "certain information which should have been revealed at the October 2-3, 2012 hearing." Specifically, Ms. Greenlaw sought "documentation of inter-communications between SCE&G and the Nuclear Regulatory Commission concerning the NRC's providing a July 2011 date as possible or probable for the awarding of the COL license." Ms. Greenlaw went on to request that such documentation "include dates and the names and contact information of the specific communicants." The Commission finds that a request to compel discovery after the close of the evidentiary record is untimely. In as much as the record in this proceeding was closed at the time of the request, there is no practical need for the discovery. The fact that SCE&G and Westinghouse/Shaw anticipated the COL to be issued in mid-2011 was clearly disclosed in testimony and exhibits in Docket No 2008-196-E as was the fact that there were risks of delay in issuance. Questions concerning the reasonableness of those assumptions should have been raised at that time. Further discovery on this point is not warranted.

resistance had not begun. SCE&G had conducted nuclear operations successfully on the Jenkinsville site for decades and the environmental, geological and other conditions related to the site were well documented and understood. (Tr. at 195, 199.)

The extensive testing and verification required by the NRC for approval of the new shield building design resulted in the COL being delayed by approximately nine months. (Tr. at 195.) Again, Westinghouse/Shaw asserted that the actions of the NRC in changing the aircraft impact requirements and in requiring an extensive testing regime for the new shield building design constituted an "uncontrollable circumstance" under the EPC Contract, and was thus compensable. Westinghouse/Shaw sought a change order for their additional costs in rescheduling the project. SCE&G challenged this claim. (Tr. at 194.)

(c) Structural Module Redesign

Westinghouse/Shaw is using modular construction techniques to increase efficiencies, reduce costs, and further standardization in construction of the Units used in the ship building industry. Under this approach, components of certain buildings, including walls, floors, electrical conduit, doorways and stairways are fabricated as sub-modules at a dedicated facility offsite and are assembled as modules on site at the Module Assembly Building. Once assembled, they are lifted and set in place in the Units. Structural modules for this project are being fabricated at the Shaw Modular Solutions ("SMS") facility located in Lake Charles, Louisiana.

Westinghouse's interactions with the NRC during the design approval of the AP1000 units resulted in a determination to use higher strength steel in the structural modules being fabricated by SMS to make other design changes to improve constructability of the modules. Westinghouse/Shaw asserted that this change in the steel specified for these modules was due to "changed conditions" in the form of a new regulatory mandate. SCE&G challenged this claim. (Tr. at 205.)

(d) Rock Conditions at Unit 2

Despite test borings in accordance with industry standards, excavation at the site of Unit 2 revealed areas where the upper level of bedrock was deeper than anticipated. This condition required additional excavation and filling with concrete to create a level base mat for the Unit. Mr. Byrne testified that it is not unusual upon excavation at a site to find that rock conditions are not uniform and require additional work resulting in an increase in costs. In this case, Westinghouse/Shaw had a valid claim to recover additional costs resulting from unanticipated rock conditions, which SCE&G did not contest. Mr. Byrne testified that SCE&G's audit of the supporting documentation for this claim by New Nuclear Development ("NND") teams resulted in its reduction by several hundred thousand dollars. He testified that the resulting settlement amount for unanticipated rock conditions was fully justified and reasonable. (Tr. at 207.)

(e) SCE&G Negotiation and Review of the Westinghouse/Shaw Claims

As to all the claims related to Change Order No. 16, members of the NND teams reviewed detailed documentation supporting the costs underlying them and assessed the level of those costs based on their construction and engineering experience. (Tr. at 195, 203, 206-07). In the end, as Mr. Byrne testified, no costs were approved that were not documented and substantiated. As a result of the initial cost documentation review and negotiations on the part of SCE&G, Westinghouse/Shaw revised their cost estimates downward, and reduced their overall claim from $213.6 million to $188 million. SCE&G also challenged Westinghouse/Shaw's entitlements to claims, and, as a result of continued review and negotiation, ultimately convinced Westinghouse/Shaw to settle the full package of claims for $137.5 million. In addition, SCE&G

directed Westinghouse/Shaw to take advantage of the opportunity created by the delay in the construction schedule for Unit 2 to optimize construction schedules between the Units. Doing so created efficiencies which allowed Westinghouse/Shaw to reduce their claim for COL delay costs by approximately $15.9 million. (Tr. at 190.) ORS also reviewed the request related to Change Order No. 16 in detail and concluded that the costs were reasonable and prudent. (Tr. at 1059, 1061, 1062.)

(f) Findings of Fact Related to Change Order No. 16

The Commission finds that SCE&G has demonstrated that the adjustments to cost schedules associated with Change Order No. 16 are not the result of imprudence by the Company but represent the necessary cost of the project. Further, Change Order No. 16 reflects the cost of a reasonable and well-negotiated resolution to a complex and difficult set of claims. The Commission finds, as Mr. Byrne testified, that the Company prudently reviewed the claims being presented, and appropriately challenged them and the assumptions underlying them as necessary. The Commission finds that the amount of the settlement is reasonable and that the benefits of such a settlement to the project, as Mr. Marsh and Mr. Byrne testified, are considerable, particularly compared to the prospect of the potential divisiveness, distraction and expense of litigating claims of such complexity.

(g) The Challenge to Macro-Corridor Approach for Siting Transmission Lines

An Environmental Report ("ER") is the basis on which an Environmental Impact Statement ("EIS") is issued for a project such as this under the National Environmental Policy Act or NEPA. (Tr. at 198, 662-63.) For an electric generation project, the Environmental Report must assess the environmental effects of any new transmission lines that are necessary to support the project.

Under the approach used by SCE&G and other utilities, the determination of the precise routing of new transmission lines is a careful process, involving substantial outreach and data collection from landowners, local governments and local communities. The process also involves public record surveys and field surveys, and reviews of existing historical, cultural and environmental data from other sources. Typically, a final route is determined only after this work is done.

To accommodate this outreach, data collection and public input process, it is an accepted practice in the industry to file Environmental Reports for new generating plants showing the general route or "macro-corridors" in which transmission lines will be sited. The Environmental Report quantifies the environmental impacts expected from lines sited in those corridors based on general data about environmental conditions and ecosystems, flora and fauna, and other concerns within the corridors. The utility commits that in constructing and siting the lines it will conform to all environmental regulations and mitigation requirements, protecting these ecosystems, flora and fauna as required by law. (Tr. at 200). The specific route of the lines within those corridors, however, is only determined after the public input process is completed.[12]

During the hearing in this docket, SCEUC challenged several of the SCE&G witnesses concerning the Company's use of the macro-corridor approach in filing its initial COL application and associated Environmental Report on the project. The record shows that SCE&G has successfully used the macro-corridor approach in permitting generation sites in the past. (Tr. at 201.) It did so in this case with the advice and support of highly experienced environmental consultants. In addition, Southern Company successfully employed the macro-corridor approach

[12] By Order Nos. 2011-978 and 2012-730, the Commission has approved and issued SCE&G a Certificate of Environmental and Compatibility and Public Convenience and Necessity for the construction and operation of the transmission lines that will extend the Units and carry power to SCE&G's load centers.

in siting and permitting its AP1000 units at Vogtle. (Tr. at 201.) In SCE&G's case, the macro-corridor approach garnered no objections during the scoping process and initial review of the filings. However, more than one year into the review process, the EPA, a commenting agency, asserted that the macro-corridor approach was unacceptable. This required SCE&G to fully site its transmission lines before the process could proceed. (Tr. at 201-02.)

SCEUC suggested that the rejection of the macro-corridor approach made SCE&G partially to blame for the NRC's delay in issuing the COL, and thus caused SCE&G to settle the Change Order No. 16 claims on less favorable terms. SCEUC put forth no witnesses or affirmative evidence on this point. SCE&G's witnesses' affirmatively testified that the use of the macro-corridor approach was reasonable and prudent in all respects. There is no evidence that SCE&G changed its negotiating approach or granted any concessions in its negotiations with Westinghouse/Shaw based on these issues.

The Commission finds that there is no credible evidence in the record of this proceeding sufficient to allow it to conclude that the use of the macro-corridor approach by SCE&G was imprudent or unreasonable. Rather, all the available evidence points to the contrary conclusion. Furthermore, the EIS was issued months before the COL. (Tr. at 202-03.) For that reason, the Commission finds on the record here, that there is no evidence sufficient to show that one delayed the other. Moreover, the Commission finds that the assertion that the delay in issuance of the EIS impacted SCE&G's bargaining position in this matter is purely speculative.

2. Owner's Cost

The Company is seeking BLRA approval of $131.6 million in updates to Owner's Cost. Owner's Cost, as Ms. Walker testified, includes costs that SCE&G will incur in overseeing the construction project; recruiting, hiring, housing and training staff for the Units; preparing written operating procedures for operations maintenance; ensuring the safety and security of the Units; accepting, testing and maintaining the systems and components comprising the Units as they are completed and turned over to SCE&G; providing the materials and supplies needed for maintenance of plant systems up to the date of commercial operation; testing of the Units when they are released for that purpose; and in conducting start-up activities. (Tr. at 709.) Owner's Cost also includes a number of construction related cost items for which the EPC Contract makes SCE&G responsible. These items include workers' compensation insurance for all contractors and subcontractors on the site; builder's risk insurance; transportation insurance related to the equipment and components of the project; miscellaneous taxes including real property and certain sales taxes associated with the project; electric power and other utilities for the project; site security; and certain preconstruction costs associated with the site. *Id.*

The current Owner's Cost forecasts reflect detailed cost-center-by-cost-center budgeting by the cost center comprising the New Nuclear Development ("NND") teams. These teams have direct responsibility for the project. In addition, detailed cost-center-by-cost-center budgets have been prepared for the support services that the project will receive from other, non-nuclear areas within SCE&G and SCANA. Such costs include support services from areas such as SCANA Audit Services, Legal, Treasury, Environmental, Forestry Services, Risk Management and Insurance, Facilities Management, and multiple groups within current Nuclear Operations (*e.g.*, groups like Unit 1 Health Physics that may assist on an as-needed basis in creating staffing plans and writing operating procedures for parts of Unit 2 & 3 operations). Each cost center that anticipated direct support to the project was required to create a budget by cost type for each year through 2018 and update the budgets annually. These budgets were carefully reviewed by Ms. Walker and the Nuclear Finance group. (Tr. at 711-13.)

The Owner's Cost budget was sponsored by Ms. Walker. (See Tr. at 713, Chart B). It is a detailed budget document with over 400 individual line items. SCE&G has made the back-up information related to this budget available for review by ORS and all other parties, provided that reasonable arrangements related to confidentiality are made. (Tr. at 715.) No party has filed any testimony challenging the prudency or reasonableness of any of the costs reflected in such Owner's Cost budget.

In Hearing Exhibit No. 6 (CLW-2), Ms. Walker provided an item-by-item analysis of the cost adjustments being presented for review in this docket. In an effort to provide more detailed information about the changes driving the $131.6 million in newly-itemized Owner's Costs, Ms. Walker provided testimony breaking down the $131.6 million into its principal categories and showing the changes from the previously approved budgets.

(a) Updated Staffing

The largest component of SCE&G's proposed adjustment to Owner's Cost is represented by changes to staffing. As Mr. Lavigne testified, the initial Owner's Cost projections were prepared during the period 2005-2008 based on the best information obtained from utility and nuclear trade groups, other prospective AP1000 owners, nuclear technology companies, internal SCE&G personnel with experience in nuclear operation and overseeing major construction projects and other sources. After the EPC Contract was signed, SCE&G intensively reviewed the initial staffing, hiring and training plans for the Units based on emerging data related to the integrated site schedule, the AP1000 design, its operating and maintenance requirements, and emerging security and regulatory requirements. Such reviews also took into account SCE&G's experience in supporting the construction project and in meeting the requirements of its role and function in overseeing the cost, quality and timeliness of the project. (Tr. at 557.) The staffing plan resulting from that review was approved in Docket No. 2010-376-E.

Since that time, Mr. Lavigne testified, SCE&G has continued to review Owner's Cost forecasts as additional information emerged concerning plant design, the events at Fukushima, security requirements at the plant, difficulties obtaining and licensing personnel, and delays in the issuance of certain permits and licenses. In the latter part of 2011, the Company established "challenge boards" comprised of experienced personnel from Unit 1 and other areas of SCE&G. The members of these boards had diverse backgrounds in nuclear operations, safety, security, plant operations and maintenance, engineering, quality systems, training, construction, planning and scheduling, outage, organizational development and planning, licensing, chemistry, documents and records, materials and procurement, health physics, and emergency planning. The challenge boards concluded that the staffing plan at that time did not provide for the hiring and training of sufficient personnel to manage startup and operate the Units reliably and effectively. (Tr. at 559.)

The reviews and refinements to staffing resulted in the addition of 95 full time equivalents ("FTEs") in Operational Readiness, 29 FTEs in Construction Oversight, Quality Assurance/Quality Control ("QA/QC") and other project support functions, and 20 FTEs in nuclear security contracting, representing a net adjustment of $72.3 million. On a functional basis, these affected areas include: (1) Emergency Planning/Health Physics (Fukushima), (2) Operator/Training Margin, (3) APOG/Programs/Procedures, (4) Timing Variance to Support Craft, (5) Nuclear Construction Oversight and QA/QC, (6) Security Contractors, and (7) Other. (Tr. at 562.)

These updates in FTEs and in costs are set forth in the table below which is taken from Mr. Lavigne's testimony. The costs presented here reflect both the cost of additional FTEs and the cost of accelerating the hiring date of existing FTEs where doing so has been found to be important to support the training and testing schedule for the Units or otherwise meet the needs of the project.

Table D

Staffing Changes by Functional Cause

Cause	**FTE Change**	**Cost Change (millions)**[13]
Emergency Planning/Health Physics (Fukushima)	40	$5.9
Operator/Training Margin	30	$17.4
APOG / Programs / Procedures	22	$15.7
Timing Variance to Support Craft and Technical Training Program	3	$15.5
Nuclear Construction Oversight and QA/QC	26	$8.6
Other	3	$3.1
Total SCE&G	**124**	**$66.2**
Security Contractors	20	$6.1
TOTAL	**144**	**$72.3**

(i) Operator/Training Margin

As Mr. Lavigne testified, the largest single driver of the staffing cost adjustment is in the area of Operator/Training Margin. SCE&G cannot complete testing and begin start up of the Units unless, when it has completed construction of the Units, the NRC is satisfied that SCE&G has sufficient reactor operators trained, licensed and ready to allow fuel to be loaded. The staff

[13] The labor costs that form part of Owner's Cost are not annual salary costs. Instead, they represent the labor costs and associated costs incurred over the ten-year life of the project for members of the NND teams. For that reason, if the decision is made to accelerate the hiring of a position by three years, all other things being equal, then there would be no increase in FTEs for the project. However, the Owner's Cost budget would increase by three times the annual salaries, benefits, facilities, IT charges and other costs associated with having that individual on staff. For that reason, the change costs for a category listed above does not necessarily correlate to the change in FTEs for that category.

of licensed operators must be sufficient to staff the Units twenty-four hours a day, seven days a week with allowances for training time and personal leave and other absences for operators. Industry experience has shown that it takes 3-7 years to train and license a nuclear reactor operator.

Mr. Lavigne testified that hiring and training reactor operators have become more difficult in recent years. Given the nature of today's military, fewer candidates are available for reactor operator training who have significant nuclear experience. Due to the aging workforce of reactor operators nationally, the industry is hiring in anticipation of impending retirements. As a result, competition to attract and retain good reactor operator candidates is more intense than in the past. Furthermore, the training and testing requirements for licensure by the NRC have increased dramatically in recent years. (Tr. at 566.) As Mr. Lavigne testified, another utility recently experienced a surprisingly high failure rate when a cadre of newly-trained candidates sat for their licensure examinations. Mr. Lavigne succinctly summarized the challenge, stating "we must train less experienced candidates with less practical exposure to the work to meet higher licensing standards while facing greater competition to retain them."

In response to this challenge, SCE&G is proposing to hire more operator candidates and to hire them sooner. Hiring candidates earlier allows more time to train them. Hiring a larger group of candidates creates a buffer to protect against higher than expected attrition and exam failure rates among candidates. The change in Operator/Training Margin represents 30 FTEs and $17.4 million of the staffing related update. (Tr. at 564-66.)

(ii) Emergency Planning/Health Physics

Another significant driver of the updated personnel costs presented here is in the Emergency Planning/Health Physics area. Mr. Lavigne testified that the industry and NRC are placing greater restrictions on the responsibilities that can be assigned to emergency personnel as a lesson-learned from the Fukushima event. Past practice allowed for emergency personnel such as fire brigade members and health physics workers to assume additional duties that were not anticipated to interfere with emergency response capabilities. In addition, emergency response personnel at one unit were assumed to be available to supplement the staff responding to a disaster at a sister unit. (Tr. at 563.) As a result of Fukushima, the NRC has published guidance limiting the number of collateral duties that may be assigned to emergency response personnel. The industry and NRC now require staffing at levels that provide a full complement of staff to be available to respond to each unit assuming simultaneous disasters at all units on a site. Mr. Lavigne testified that these new limits on shared duties for emergency personnel results in the need for an additional 40 FTEs at a cost of $5.9 million. (Tr. at 563-64.)

(iii) APOG/Plant Programs/Procedures

An important part of preparing a new nuclear unit for operation is drafting and promulgating the plant programs and procedures that are necessary to operate and maintain the Units, respond to events and emergencies and provide for security and related functions. SCE&G has determined that operating and maintaining these Units will require drafting approximately 100 plant programs (*e.g.*, the Thermal Performance Program, the Equipment Reliability Program, and the System Status Control Program) and 4,200 procedures. Prior cost forecasts were based on the assumption that the burden and cost of drafting these programs, most of which can be uniform across AP1000 units, would be borne by five AP1000 owners comprising the AP1000 Owner Group ("APOG".) However, at present only two of the five members of the group, SCE&G and the Southern Company, have active EPC contracts with Westinghouse/Shaw. As a result, only these two members have the right under their agreements to have access to Westinghouse/Shaw's proprietary design and engineering data related to the Units. Such access is necessary to participate in the shared drafting exercise. As a result, SCE&G and Southern Company must share the drafting responsibilities among themselves rather than among a group of five utilities. This has resulted in the need for 22 additional FTEs and represents $15.7 million of the requested cost. (Tr. at 566-68.)

(iv) Timing Variance to Support Craft

The safe and efficient operation of the Units will require a staff of well-trained craft workers in areas such as chemistry, maintenance, outage and planning, and scheduling. In reviewing its staffing plans through the challenge board process, SCE&G determined that three additional FTEs would be required in this area to ensure that a sufficient number of trainees will successfully complete the INPO accredited training programs in their areas of specialization. SCE&G also concluded that it is important that certain Unit 2 and 3 craft workers be trained earlier than expected so that they can be given the opportunity before commercial operations of those Units begin to develop hands-on experience with nuclear operations and with the systems comprising Units 2 and 3. For that reason, Mr. Lavigne testified that SCE&G had decided to hire and train craft workers earlier than anticipated to allow them to work with Westinghouse/Shaw personnel during the startup of the Units and to work alongside their colleagues at Unit 1 doing similar tasks there. The Timing Variance to Support Craft results in three additional FTEs and an increase to Owner's Cost of approximately $15.5 million. (Tr. at 568-69.)

(v) Nuclear Construction Oversight and QA/QC

Based on experience gained so far in constructing the Units, the Company has determined that additional personnel are needed to effectively oversee the cost, quality and safety of the project. As Mr. Lavigne testified:

> [T]here is no substitute for the accountability provided by an owner's direct involvement and insistence on quality and timely work. The NRC concurs in this, and has made it very clear that they hold SCE&G ultimately accountable as owner/licensee for the quality, reliability and safety of the Units as constructed. They expect SCE&G to be actively and directly involved in overseeing all aspects of the work and we agree. The value of additional personnel to oversee the construction effort and the world-wide procurement chain for this project cannot be overstated.

(Tr. at 569-70.) To support the desired level of QA/QC oversight, SCE&G has added 26 FTEs totaling $8.6 million of the update. (Tr. At 570).

(vi) Security Contractors

The size of the work force required to provide security to the site is determined by threat response planning. Such planning is based on current NRC and industry guidance as to anticipated levels of threat and the required levels of security response. Threat response planning is very site-specific and depends on the precise layout of support buildings, access points and site topography. For that reason, an updated count of security personnel needed for the Units could not be completed until the layout and configuration of the facilities on site was finalized. Since 2010, Westinghouse/Shaw's design work has progressed to the point that the site layout is well established. Based on this information, and current NRC guidance related to security planning, SCE&G has updated its security staffing plans for the Units. These refinements have resulted in SCE&G adding 20 additional FTEs for security contractors at a cost of $6.1 million. (Tr. at 570-71.)

(vii) Other

Under the Other category are costs associated with the personnel necessary to ensure that all Westinghouse/Shaw records are obtained and captured for current and future use and are secured as required by the NRC regulations. These are QA/QC, engineering, construction and security related documents that are of important to future operations and regulatory compliance. The number of required personnel for these tasks has increased while demand for staff in areas of business and finance have decreased. (Tr. at 570.) The net result is an increase in forecasted staffing of three FTEs and cost of $3.1 million.

(viii) SMS Oversight Costs

For a number of years, SCE&G has expressed concerns in update dockets and quarterly reports concerning the difficulties SMS was experiencing in establishing an effective nuclear safety culture at its facilities in Lake Charles, Louisiana. Over time, SCE&G has steadily increased its level of QA/QC oversight for SMS. Recently, SCE&G has taken the steps of placing a full time presence dedicated to owner's quality inspection at the SMS site, in addition to the dedicated QA/QC personnel located there by Westinghouse/Shaw.

At the hearing, certain parties raised concerns about SCE&G's inclusion in its forecasts of costs associated with additional costs SCE&G incurred in providing QA/QC oversight for SMS.

The Commission understands the impulse to require SMS to absorb these costs. However, it is customary in the industry, and beneficial for many reasons, for an owner's QA/QC efforts to be at its sole expense and under its exclusive authority. The EPC Contract does not provide for recovery of QA/QC expense from any other party, nor would the Commission expect it to. Under the BLRA, specifically S.C. Code Ann. § 58-33-270(E), there is no basis to rule that it was imprudent on SCE&G's part to invest additional resources in overseeing QA/QC issues at the SMS facility. To the contrary, such an investment is prudent to a very high degree. For that reason, the Commission finds that the SMS oversight costs, and oversight costs related to other suppliers and contractors, are reasonable, prudent and necessary costs of the project and should be included in the approved capital cost schedule.

(ix) Findings Related to Staffing Costs

The Commission has reviewed the testimony and evidence presented in this docket that is related to the update in staffing costs. No evidence has been presented that is sufficient to allow the Commission to conclude that these changes were the result of imprudence by SCE&G. For the reasons stated above, and in the testimony of Mr. Byrne, Mr. Lavigne, and Ms. Walker, the Commission finds that these increases in the forecasted cost of staffing are not the result of imprudence on the part of SCE&G but instead represent reasonable, necessary and prudent costs of the project.

(x) APOG Programs/Procedures and Related Cost Increases

At the hearing, certain parties seemed to question the appropriateness of the cost forecasts for the project being increased as a result of the change in the drafting of plant programs and procedures related to APOG. The evidence clearly establishes that drafting of these programs and procedures is a reasonable, necessary and prudent part of the project. Through APOG, SCE&G is sharing the cost of this effort with the Southern Company, which will reduce the cost borne by SCE&G's customers significantly. SCE&G is acting prudently in using APOG to share these costs with additional utilities. While it would be beneficial if more utilities could share in the efforts requiring proprietary data, SCE&G cannot dictate to Westinghouse how it enforces its intellectual property rights as they affect this effort. No party offered any affirmative evidence showing that SCE&G has acted imprudently in its dealings with APOG or with the cost of drafting the required programs and procedures. Instead, the evidence shows that SCE&G has acted prudently to reduce costs to customers by having as many utilities as possible share the cost and burden of this effort. The Commission finds that the increase in cost related to APOG Programs/Procedures is a reasonable, prudent and necessary cost of the project and should be included in the approved capital cost schedule.

(b) Facilities

The facilities component of Owner's Cost includes the construction, up-fitting and furnishing costs of the buildings, and training facilities needed to support the operations of the Units once they are constructed, and the cost incurred in providing training, office and other space for the NND teams and other members of the project team during the construction period. All of these costs are not annual costs but costs to be incurred over the ten-year course of the project. (Tr. at 718-21.)

SCE&G's witness, Ms. Walker, presented the updates to facilities costs that form part of the Owner's Cost update and provided a detailed breakdown of the categories and drivers of these costs. She testified that additional maintenance costs amounting to $1.9 million comprised the largest single item in this cost category. These costs are the direct result of the accelerated hiring of staff detailed in Mr. Lavigne's testimony. (Tr. at 719). The accelerated hiring schedule also drives the need to add modular buildings and temporary office space in the facilities plan during the construction period. The cost of these additional facilities represents approximately $1.0 million. Other changes in the cost of facilities result from the increased number of dedicated emergency personnel required in response to the events at Fukushima and the facilities required to house those personnel and equipment. Similarly, additional site planning and security planning have identified additional costs related to site-specific security facilities and other facilities related to site access. In total, the update to facilities costs represents $7.8 million of the increase in Owner's Cost. (Tr. at 721-722.)

No party in this proceeding presented any direct evidence challenging the reasonableness or prudence of these updates to facilities costs. In its testimony, ORS's witness, Mr. Jones, found these costs are justified and reasonable. (Tr. at 1071.). Based on the testimony of Ms. Walker and Mr. Jones, the Commission finds these costs to be necessary, reasonable and prudent costs of the project. The Commission finds that no party has made any showing that these costs are in any way the result of imprudence on the part of SCE&G. It is appropriate to reflect these costs in the approved cost forecasts for the project.

(c) Information Technology ("IT") Roadmap

Effective IT infrastructure is critical to safe and efficient nuclear operations. A major part of such infrastructure is the software that is used in tracking the maintenance history of parts and equipment, documenting scheduled and preventative maintenance, tracking spare parts and inventory on hand, recording where specific parts have been used in the plant, scheduling maintenance requests, preparing work schedules, administering employee fatigue management and safety rules, and ensuring that safety and quality assurance documentation is maintained and available for use and inspection. (Tr. at 715-717.)

Ms. Walker testified to SCE&G's update to the cost forecasts for delivering IT services to the project through its witness. According to Ms. Walker, the IT budget presented in Docket No. 2010-376 was a roll-up of individual budgets for IT services formulated by the managers in each NND area for their areas. In most cases, these budgets relied on the assumption that existing Unit 1 programs and infrastructure could be scaled up to meet the IT needs of Units 2 and 3. (Tr. at 716.)

In 2011, SCANA's IT department ("SCANA IT") was tasked with creating a formal and detailed "IT Roadmap" for the project based on a thorough inventory of the available software, infrastructure and licenses, and the needs of the project and the Units. Based on its review, SCANA IT concluded that much of the IT infrastructure in use at Unit 1 was not scalable to support the new Units.

No party in this proceeding has challenged the prudency of the costs associated with implementing the new IT Roadmap. While Dr. Cooper testified that he was concerned that Unit 1 IT upgrade costs might be included in the Unit 2 and 3 cost estimates (Tr. at 971.), Mr. Byrne refuted that testimony. (Tr. at 277-78.) The Commission finds Mr. Byrne's testimony to be credible and finds no basis to conclude that Unit 1 IT costs are improperly included here.

For the reasons stated in Ms. Walker's testimony, the Commission finds that these additional IT costs are not the result of imprudence by the Company but that they are reasonable, necessary and prudent costs of the project. The Commission finds that it is appropriate to reflect them in the approved cost forecasts for the project.

(d) Conclusions as to Owner's Cost Updates

The testimony of Mr. Byrne, Mr. Lavigne and Ms. Walker and Mr. Jones provides sufficient evidence supporting the reasonableness and prudence related to each of the components making up the $131.6 million adjustment. The record shows that Ms. Walker testified as to the reasonableness and prudency of each of these items and to the reasonableness and prudency of the overall $131.6 million adjustment to the Owner's Cost category. (Tr. at 708-09.) Her testimony is supported by similar testimony from Messrs. Marsh, Byrne and

Lavigne. (Tr. at 43, 165, 572.) ORS also conducted its own review and provided testimony finding that the $131.6 million of Owner's Cost represents a "reasonable cost increase for the Project." (Tr. at 1072.) The key drivers as to each element of cost have been presented clearly and distinctly in the evidence contained in this record.

As to the reasonableness of the budgets and budget process on which these Owner's Cost adjustments were based, Ms. Walker testified:

> The budgets for each [item of Owner's Cost] have been carefully reviewed and evaluated for reasonableness. This analysis confirms the reasonableness of the adjustment in Owner's Costs for the categories listed above, and supports the conclusion that the updated Owner's Costs budget is a reasonable and prudent estimate of the cost associated with this construction project.

(Tr. at 770.) In addition to this testimony, ORS witness Jones testified that ORS has reviewed these costs and has determined them to be reasonable. (Tr. at 1043.)

For all the reasons set forth above, and having reviewed the testimony and the exhibits in the record of this proceeding, the Commission finds that no party has presented evidence showing that the $131.6 million adjustment to Owner's Cost is in any way the result of imprudence by SCE&G. Instead, the Commission finds that the update reflects a reasonable, necessary and prudent adjustment to the cost schedules for the project, and that there is no evidence in the record to suggest that they are the result of any imprudence on the part of the Company.

3. Transmission Cost

Since the issuance of Order No. 2011-345, the Company has continued to update its Transmission cost forecast to reflect current information concerning the design and siting of the lines and other facilities, and the costs of right-of-way siting proceedings. SCE&G has updated its Transmission cost forecast by $7.9 million. This net increase in the Transmission cost forecast is comprised of increases of (1) $1.6 million to construct a new Saluda River Transmission ("SRT") substation, (2) $3.6 million for other transmission line construction, (3) $2.7 million to upgrade various substation equipment, and (4) $1.4 million for right-of-way and property acquisition. This amount also reflects a decrease resulting from a reallocation of costs between SCE&G and Santee Cooper of $1.4 million.

(a) The SRT Substation

SCE&G originally planned to accommodate the delivery of power from the Units into the load centers in the Lexington and Lake Murray areas by adding additional autotransformers at its existing Lake Murray 230/115 kV Substation and its Denny Terrace 230/115 kV Substation. (Tr. at 648.). However, as Mr. Young testified, recent engineering work showed that the two existing substations did not have sufficient space to allow new autotransformers to be located in them without costly expansions. Those expansions would be equivalent to building new substations beside each of the two existing substations. Subsequent power flow studies showed that this plan would require a third transformer to be installed at the Lyles 230/115 kV Substation. (Tr. at 632, 646-650.) In addition, the decision to route the new lines to serve the Units on existing right-of-way created the opportunity to build the SRT substation in an area with high demand where a new substation would be beneficial.

The cost of the new SRT substation is $1.6 million more than the original cost of the autotransformers design, and is much less than the cost of that design ($27.8 million) when the costs of expanding the existing substations and adding a third transformer is considered. Other improvements benefiting the transmission system as a whole are also being made under this plan. The cost to the nuclear project is being reduced by appropriately allocating costs to system improvements where the existing transmission system, not the project to construct the Units, is the principal beneficiary of the specific costs. (Tr. at 652.)

(b) The Parr-VCSN Safeguard Line Underground

The Parr-VCSN Safeguard 115 kV Line currently provides back-up power to the safety-related components of Unit 1. (Tr. at 653.) Mr. Young testified that under the current design for the new transmission lines for the Units, the Parr-VCSN Safeguard 115 kV Line would cross five 230 kV lines at one location. In a worst-case scenario, the Parr-VCSN Safeguard Line could fall on these lines and cause all six lines to go out of service resulting in a loss of service to a large number of customers. To alleviate reliability and safety concerns related to this configuration, a short segment of the Parr-VCSN Safeguard Line will be rebuilt underground at a cost of $2.9 million. (Tr. at 655.)

(c) Lowering the Parr-Midway Line

The current design for the lines serving the site results in seven 230 kV lines crossing the Parr-Midway 115 kV lines. Further design and engineering reviews have shown that in the area of crossing that SCE&G must lower the Parr-Midway 115kV lines to meet NERC safety guidelines. Mr. Young testified that lowering these lines is the most cost effective solutions to address these safety concerns. The cost for lowering these lines is $704,000. (Tr. at 656.)

(d) Various Substation Improvements

Mr. Young testified that continued design work and power flow analysis had shown that improvements to several substations across the system were required to safely and efficiently route the power from the Units to customers. Because the existing disconnect switch at V.C. Summer Switchyard No. 1 does not have the power current rating necessary to function properly when Units 2 and 3 become operational, SCE&G must replace a bus side disconnect switch as well as existing lightning arresters. The cost for these changes is $614,000. Similarly, recent transmission design and engineering work has shown that SCE&G must also make improvements at three existing substations in order to increase their power ratings and interconnect new transmission lines with SCE&G's existing system. These improvements include an upgrade to the bus and terminal at the Canadys 230 kV Substation, an upgrade to the terminal at the Summerville 230 kV Substation, and the upgrade of two terminals at the Saluda Hydro Substation. The estimated cost for these three substation improvements is $2.1 million. (Tr. at 657-59.)

(e) Costs of the Blythewood-Killian Segment

The Company is constructing the Blythewood-Killian Segment of the VCS1-Killian 230kV Line along new right-of-way. Building this segment requires SCE&G to obtain, through purchase or condemnation, right-of-way for that line. Based on the results of siting studies like those discussed above, the line as finally sited crosses an area of higher property values than was originally anticipated. Based on actual right-of-way costs incurred to date, the right-of-way cost forecast has increased by $369,000. Several condemnations are ongoing and changes to these costs are possible but are not expected to be material. (Tr. at 660.)

In Docket No. 2011-325-E, SCE&G entered into settlement agreements with Richland County and with the Town of Blythewood concerning legal challenges that they brought to the siting of the Blythewood-Killian segment in areas of concern to them. Both political subdivisions intervened in the Commission siting proceeding for the line and actively opposed the siting of the line as SCE&G proposed. SCE&G estimates that had Richland County and the Town of Blythewood prevailed in their request to reroute the line, the additional costs to the project would have been $6.3 million and $26.0 million, respectively. (Tr. at 662.) Complying with the request of the Town of Blythewood could have also delayed the issuance of the COL because the resulting route of the transmission lines would have been inconsistent with the route set forth in the ER on which the EIS for the COL was based.

SCE&G settled its dispute with Richland County for $1.0 million and with the Town of Blythewood for $450,000. The Richland County settlement included payment for a contested right-of-way easement across a large tract of County-owned land. Both settlements resolved all outstanding issues between the political subdivisions and the Company relating to the siting of the line. (Tr. at 661-63.) Pursuant to the Commission's decision in Order No. 2009-104(A) concerning allocation of the costs of these lines between the project and general transmission system improvements, SCE&G is currently requesting 74.2% of the settlement amounts be included in the cost schedules for the Units.

(f) Reductions to Allocations to Santee Cooper

The costs listed above are offset in part by a reduction in cost allowed to SCE&G for facilities that benefits both SCE&G and Santee Cooper. Historically, SCE&G and Santee Cooper have allocated the cost of shared-use transmission assets at the VC Summer site on an item-by-item basis. Specific allocations were made for individual switches, structures, and other pieces of equipment. Recently, SCE&G and Santee Cooper have agreed instead to allocate costs based on the proportion that each makes use of specific facilities like switchyards and lines rather than individual components of them. The resulting reallocation of costs between Santee Cooper and SCE&G results in a $1.4 million decrease to Transmission cost forecast. (Tr. at 664-65.)

The Commission has carefully reviewed the evidence and testimony related to Transmission cost presented by the Company discussed above as well as the testimony and conclusions of the ORS (Tr. at 1123). The Commission finds that there is no evidence establishing imprudence on the part of SCE&G. No party presented evidence contesting these costs. The Commission finds these costs to be reasonable, prudent and necessary costs of the project. They are properly included in the updated costs forecasts.

4. Other Change Orders

The cost schedules presented here for approval contain costs associated with three change orders that predate the Change Order No. 16 settlement and relate to different scopes of work. Those three additional change orders are Change Order Nos. 12, 14 and 15.[14] They reflect additional costs for compliance with new federal healthcare mandates, cyber security measures, and the minor redesign of a wastewater piping system.

Collectively, Change Order Nos. 12, 14 and 15 represent $5.9 million of the cost update at issue here. Of these change orders, Change Order No. 14 related to cyber security represents more than 95% of the total $5.9 million amount. Company witnesses Mr. Byrne and Ms. Walker provided testimony as to the reasonableness and prudency of the costs reflected in these change orders. (Tr. at 208-212, 723-24.)

(a) Change Order No. 12

Change Order No. 12 is based upon a request by Westinghouse/Shaw for reimbursement of Shaw's increased costs as a result of a change in law related to portions of the Health Care and Education Reconciliation Act of 2010 (the "Health Care Act") and prior health care acts. (Tr. at 210.) The total costs associated with this change are $135,573 and such costs spread throughout the remaining period of the project. Mr. Byrne testified that SCE&G has verified the amounts involved and that they are accurate. He testified that the additional health care costs are the result of new legal requirements imposed on Westinghouse/Shaw and that they are reasonable,

[14] Change Order No. 13 was a no-cost change order related to IT workstations for plant operators.

necessary and prudent costs of the project. (Tr. at 211.) Westinghouse/Shaw may identify other change orders related to heath care costs but no additional change orders have been identified to date. (Tr. at 210.)

(b) Change Order No. 14

As Mr. Byrne testified, it has become critical as a matter of national security to protect key electric infrastructure against cyber-attack. The NRC now requires robust cyber security measures to be incorporated in all new and existing nuclear facilities. SCE&G has reached an agreement with Westinghouse/Shaw to use a phased approach for ascertaining the costs associated with strengthening the Unit's defenses against cyber-attacks. (Tr. at 209-10.) Change Order No. 14 reflects costs related to strengthening the Units' defenses against cyber attacks.

Under the agreement between SCE&G and Westinghouse/Shaw, Phase I of the Cyber Security plan will involve a review of the specific equipment and software that will be used in the Units to identify potential vulnerabilities to cyber-attack. Westinghouse/Shaw will also devise a scope of work to protect against those vulnerabilities. Phase II will involve the actual software programming and other work necessary to overcome the vulnerabilities identified in Phase I. The contractual costs of Phase I and the forecasted costs of Phase II are reflected in Change Order No. 14. The combined costs of both phases are currently estimated to be $5.9 million. The final costs of Phase II will depend on the results of work done in Phase I. (Tr. 209-10.)

In his prefiled testimony, ORS witness Mr. Jones expressed concerns that the cost increase estimate for Phase II of the Cyber Security regime might be premature. He suggested that the Commission should wait until Phase I is completed before approving any forecasted costs for Phase II. For that reason, he recommended that the Commission include only the

$914,422 cost of Phase I in approved forecasts and delay the requested $4.9 million cost of Phase II until a later update filing when there is a better definition of the cost, time and scope attributable to such work. (Tr. at 1062-63.)

SCE&G witnesses testified that the forecasted cost of Phases I and II are reasonable and prudent forecasts of cyber security costs and are accurate forecasts based on the current information available concerning the work to be performed. (Tr. at 210.) Future costs approved as part of the BLRA cost schedules are almost always forecasted costs. See S.C. Code Ann. § 58-33-270 (Supp. 2011). The fact that Phase II costs are forecasts does not make it premature to include them in the forecasted cost of the Units so long as there is a reasonable basis for expecting them to be spent. The estimates provided by Westinghouse/Shaw provide such a basis. The Commission finds that the costs of Phase I and Phase II of the cyber security change order are supported by the evidence of record and are properly included in the updated capital cost. Including both elements of cost in the approved forecasts ensures that those forecasts represent the best information available regarding the forecasted cost of the Units.

(c) Change Order No. 15

Change Order No. 15 pertains to additional costs associated with a revision of the design of the waste water discharge piping for the Units to provide for gravity drainage. Mr. Byrne testified that SCE&G prefers the gravity design because it involves fewer pumps, motors and other moving parts that require maintenance. SCE&G understood when it submitted its COL application that there could be a charge associated with this change but that the cost would only be known when the design was complete. Now that design work is complete, Westinghouse/Shaw has determined that the cost of this work will be $8,250. Mr. Byrne testified that SCE&G has verified this amount and finds it to be a reasonable and prudent cost that supports a beneficial change to the project design. (Tr. at 211-12.)

(d) Conclusion as to the Three Change Orders

The Commission finds that no party has shown that the cost associated with these three change orders is the result of imprudence on the part of SCE&G. Instead, the Commission finds the costs associated with these three change orders are reasonable and prudent costs of the project and there is no evidence in the record to suggest otherwise.

C. Unanticipated Costs

At the hearing in this matter, the SCEUC seemed to take the position that the Commission might disallow certain costs because SCE&G should have anticipated them when cost schedules were presented for approval in past proceedings. (See, *e.g.*, Tr. at 331, l. 22-24; 339, l. 20-25; 586, l. 11-14.) The Commission does not adopt this approach for several reasons. The Commission finds that the cost forecasts adopted in prior orders were based on extensive evidence indicating that they represented the best information available to the Company at the time they were adopted. The forecasts were fully litigated in contested case proceedings before the Commission. The ORS carefully reviewed and audited these forecasts. Public notice was given and interested parties were given the opportunity to intervene in the proceedings as parties with full rights of discovery and cross-examination. At the hearing, the Company presented extensive testimony subject to cross-examination supporting these forecasts. On the basis of that record, the Commission entered express findings that those forecasts were reasonable and prudent. See Order No 2009-104(A); Order No. 2011-345.

The Commission does not believe that it is appropriate as a matter of regulatory practice and policy, nor is it consistent with the terms and intent of the BLRA, to rule that the failure to anticipate certain costs is imprudent, where it has already ruled, after a full contested case hearing, and a full and candid presentation of cost forecast data to the Commission, that the cost forecasts being alleged to be imprudent reasonably and accurately reflected the anticipated cost of the Units at the time. To rule otherwise is neither fair nor logical and results in the sort of after-the-fact relitigation of prudency questions that the BLRA was intended to discourage.

D. Construction Milestone Schedule Changes

Company witness Mr. Byrne sponsored Exhibit No. 1 (SAB-3), which updates the construction milestone schedule for the Units to reflect the substantial completion date for Unit 2 of March 15, 2017, and for Unit 3 of May 15, 2018. (Tr. at 212.) Mr. Byrne testified that these updated schedules are based on construction milestones and equipment fabrication and procurement milestones provided by Westinghouse/Shaw in response to the decision to reschedule the Units. Based on Mr. Byrne's testimony, the Commission finds that the updates to the construction milestone schedule are prudent and reasonable in all respects. (Tr. at 212-13.) The updated construction schedule shall be substituted for Exhibit 1 to Order No. 2009-104(A).

IV. <u>CONCLUSION</u>

For the reasons set forth below, the Commission finds that the changes to the cost and construction schedules proposed by SCE&G are reasonable and prudent and comport with the terms of the BLRA. Having carefully reviewed the record in this proceeding, the arguments of the parties, and the operative provisions of the BLRA, the Commission does not find any basis for concluding that the $282.9 million in newly identified and itemized costs are in any way the result of SCE&G's failure to manage the project prudently. Instead, the evidence of record shows that the $282.9 million in newly identified and itemized capital costs are the result of the normal evolution and refinement of construction plans and budgets for the Units. The costs that

SCE&G is incurring will ensure that the project is constructed prudently and that the Units can be operated and maintained safely and efficiently when they are completed.

As to the prudency of continuing construction of the Units, the Commission finds that SCE&G has presented evidence establishing that the most prudent, reasonable and beneficial base load resource strategy for it to pursue at this time is to complete construction of the Units as proposed. The evidence shows that it would not be prudent, reasonable or beneficial to SCE&G or its customers to switch to a natural gas resource strategy.

Similarly, the Commission finds that the changes in the construction schedule presented here reflect a reasonable and prudent response to the effects of the unanticipated delay in issuing the COL for the Units and other matters. This delay was not the result of any imprudence by SCE&G. The delaying of the construction schedule for one Unit, and accelerating the schedule for the other does not in any material way change the benefit of the Units to SCE&G and its customers.

In accordance with the terms of S.C. Code Ann. §§ 58-33-270(E) and 58-33-270(G), the Commission finds that the revised cost and construction schedules presented reflect prudent costs and schedules and should be approved.

V. PROCEDURAL FINDINGS AND LEGAL STANDARDS

1. In Order No. 2009-104(A), dated March 2, 2009, the Commission approved a capital cost schedule for the construction of two 1,117 net MW nuclear power units to be located at the SCE&G's V.C. Summer Nuclear Station near Jenkinsville, South Carolina. The approved capital cost for the project totaled $4.5 billion in 2007 dollars.

2. In Order No. 2010-12, the Commission approved an updated construction schedule for the project and an updated capital cost schedule that reflected the updated

construction schedule. The capital cost schedule approved in Order No. 2010-12 did not alter the total estimated capital cost for the Units of $4.5 billion in 2007 dollars.

3. On August 9, 2010, the South Carolina Supreme Court issued its decision in *South Carolina Energy Users Comm. v. South Carolina Pub. Serv. Comm'n*, 388 S.C. 486, 697 S.E.2d 587 (2010), concerning SCEUC's appeal of Order No. 2009-104(A). In its Opinion, the Court ruled that contingency costs which had not been itemized or designated to specific cost categories were not permitted as a part of approved capital cost schedules under the BLRA.

4. In Order No. 2011-345, the Commission approved an updated capital cost schedule in response to the Opinion, which removed from approved schedules costs that had not been itemized to specific capital cost items and approved $174 million in adjustments to reflect newly itemized costs. The capital cost schedule approved in Order No. 2011-345 reduced the total approved capital cost forecast for the Units to $4.3 billion in 2007 dollars.

5. Under S.C. Code Ann. § 58-33-270(E), a utility may petition the Commission "for an order modifying any of the schedules, estimates, findings, class allocation factors, rate designs, or conditions that form part of any base load review order." The Commission shall grant the relief requested if, after a hearing, the Commission finds "that the evidence of record justifies a finding that the changes are not the result of imprudence on the part of the utility."

6. On May 15, 2012, SCE&G filed the Petition in this docket, pursuant to S.C. Code Ann. § 58-33-270(E) (Supp. 2010), seeking an order approving an updated capital cost and construction schedules for nuclear units.

7. The Commission convened a public hearing on this matter on October 2, 2012, which concluded on October 3, 2012.

8. No party presented any testimony or other evidence sufficient to overcome the Company's affirmative testimony supporting the fact that the $283 million in newly identified and itemized costs are prudent costs and are not in any way the result of SCE&G's failure to manage the project prudently.

VI. FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. The updated capital cost schedule contained in Hearing Exhibit No. 6 (CLW-1) reflects $283 million in costs that have not previously been presented to the Commission for review and approval.

2. This $283 million is comprised of approximately $137.5 million attributable to Change Order No. 16, representing the settlement of several matters between Westinghouse/Shaw and SCE&G; $131.6 million in newly identified and itemized Owner's Cost; $7.9 million in newly identified and itemized transmission costs; and $5.9 million in costs associated with certain change orders that have been negotiated and identified to the EPC Contract for the Units.

3. The evidence in the record demonstrates that the $282.9 million in newly identified and itemized costs are the result of the normal evolution and refinement of construction plans and budgets for the Units and are not the result of imprudence on the part of SCE&G.

4. These additional costs are reasonable, necessary and prudent costs that SCE&G is incurring as owner of the project to ensure that the project is constructed prudently, efficiently and economically, and to ensure that the Units can be operated and maintained safely and efficiently when they are completed.

5. The updated capital cost schedule contained in Hearing Exhibit No. 6 (CLW-1) also appropriately reflects changes to the cash flow forecast that have resulted from changes in the expected timing of construction costs.

6. The evidence in the record demonstrates that the changes in project cash flows represent the reasonable and necessary updating of cash flow projections and do not represent imprudence on the part of the Company.

7. The updated milestone construction cost schedule contained in Hearing Exhibit No. 1 (SAB-3) reflects the delay in the substantial completion of Unit 2 until March 15, 2017, and the acceleration of Unit 3 to May 15, 2018. The evidence shows that the delay in the NRC issuing the COL was the principal cause of the nine-month delay of this critical path item.

8. The evidence in the record shows that the delay in the substantial completion date of Unit 2 and the acceleration of the completion of Unit 3 supports updating the construction milestones for the Units and is not the result of any imprudence on the part of SCE&G.

Now, therefore, IT IS HEREBY ORDERED:

1. That the capital cost schedule set forth in Hearing Exhibit No. 6 (CLW-1), attached hereto as **Order Exhibit No. 1**, shall be the approved capital cost schedule for the Units until such time as the Commission approves a substitute schedule pursuant to S.C. Code Ann. § 58-33-270(E).

2. That the construction milestones schedule set forth in Hearing Exhibit No. 1 (SAB-3), attached hereto as **Order Exhibit No. 2**, shall be the approved construction milestone schedule for the Units until such time as the Commission approves a substitute schedule pursuant to S.C. Code Ann. § 58-33-270(E).

3. The future quarterly reports filed by SCE&G under S.C. Code Ann. § 58-33-277 shall reflect the modified schedules approved in this Order.

4. This Order shall remain in full force and effect until modified by a subsequent order of the Commission.

BY ORDER OF THE COMMISSION:

____

David A. Wright, Chairman

ATTEST:

____

Randy Mitchell, Vice Chairman

(SEAL)

Exhibit No. ____ (CLW-1-P) Public

DOCKET NO. 2012-203-E
ORDER NO. 2012-_____
__________, 2012
ORDER EXHIBIT NO. 1

Exhibit 1

RESTATED and UPDATED CONSTRUCTION EXPENDITURES

(Thousands of $)

V.C. Summer Units 2 and 3 - Summary of SCE&G Capital Cost Components

Actual through March 2012* plus Projected

		Actual					Projected						
Plant Cost Categories	**Total**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Fixed with No Adjustment	[redacted]												
Firm with Fixed Adjustment A													
Firm with Fixed Adjustment B													
Firm with Indexed Adjustment													
Actual Craft Wages													
Non-Labor Costs													
Time & Materials													
Owners Costs													
Transmission Costs	329,512	-	26	724	927	11,964	57,206	56,903	57,508	77,990	64,727	1,537	-
Total Base Project Costs(2007 $)	4,553,355	21,723	97,386	319,073	374,810	314,977	614,173	782,238	793,879	648,780	386,537	142,999	56,781
Total Project Escalation	970,629	-	3,519	20,930	23,741	34,084	99,789	169,965	215,848	184,800	134,815	58,409	24,729
Total Revised Project Cash Flow	5,523,984	21,723	100,905	340,003	398,551	349,061	713,961	952,204	1,009,727	833,579	521,351	201,408	81,510
Cumulative Project Cash Flow(Revised)		21,723	122,629	462,632	861,183	1,210,244	1,924,205	2,876,409	3,886,136	4,719,715	5,241,066	5,442,474	5,523,984
AFUDC(Capitalized Interest)	237,926	645	3,497	10,564	17,150	14,218	20,462	38,446	42,934	40,958	27,518	15,391	6,144
Gross Construction	5,761,910	22,368	104,403	350,567	415,701	363,278	734,424	990,649	1,052,661	874,537	548,870	216,798	87,654
Construction Work in Progress		22,368	126,771	477,338	893,039	1,256,317	1,990,741	2,981,390	4,034,051	4,908,588	5,457,458	5,674,257	5,761,910

CONFIDENTIAL

*Applicable index escalation rates for 2012 are estimated. Escalation is subject to restatement when actual indices for 2012 are final.

Notes:
Current Period AFUDC rate applied 5.28%

Escalation rates vary from reporting period to reporting period according to the terms of Commission Order 2009-104(A).
These projections reflect current escalation rates. Future changes in escalation rates could substatially change these projections.
The AFUDC rate applied is the current SCE&G rate. AFUDC rates can vary with changes in market interest rates,
SCE&G's embedded cost of capital, capitalization ratios, construction work in process, and SCE&G's short-term debt outstanding.

BLRA Revised Milestones
VC Summer Units 2 and 3

Exhibit No. ____ (SAB-3)

Tracking ID	Milestone Description	Revised Completion Date	Unit
1	Approve Engineering Procurement and Construction Agreement	Complete	
2	Issue P.O.'s to nuclear component fabricators for Units 2 and 3 Containment Vessels	Complete	
3	Contractor Issue PO to Passive Residual Heat Removal Heat Exchanger Fabricator - First Payment - Unit 2	Complete	
4	Contractor Issue PO to Accumulator Tank Fabricator - Unit 2	Complete	
5	Contractor Issue PO to Core Makeup Tank Fabricator - Units 2 & 3	Complete	
6	Contractor Issue PO to Squib Valve Fabricator - Units 2 & 3	Complete	
7	Contractor Issue PO to Steam Generator Fabricator - Units 2 & 3	Complete	
8	Contractor Issue Long Lead Material PO to Reactor Coolant Pump Fabricator - Units 2 & 3	Complete	
9	Contractor Issue PO to Pressurizer Fabricator - Units 2 & 3	Complete	
10	Contractor Issue PO to Reactor Coolant Loop Pipe Fabricator - First Payment - Units 2 & 3	Complete	
11	Reactor Vessel Internals - Issue Long Lead Material PO to Fabricator - Units 2 and 3	Complete	
12	Contractor Issue Long Lead Material PO to Reactor Vessel Fabricator - Units 2 & 3	Complete	
13	Contractor Issue PO to Integrated Head Package Fabricator - Units 2 & 3	Complete	
14	Control Rod Drive Mechanism Issue PO for Long Lead Material to Fabricator - Units 2 and 3 - first payment	Complete	

BLRA Revised Milestones
VC Summer Units 2 and 3

Exhibit No. ____ (SAB-3)

Tracking ID	Milestone Description	Revised Completion Date	Unit
15	Issue P.O.'s to nuclear component fabricators for Nuclear Island structural CA20 Modules	Complete	
16	Start Site Specific and balance of plant detailed design	Complete	
17	Instrumentation & Control Simulator - Contractor Place Notice to Proceed - Units 2 & 3	Complete	
18	Steam Generator - Issue Final PO to Fabricator for Units 2 and 3	Complete	
19	Reactor Vessel Internals - Contractor Issue PO for Long Lead Material (Heavy Plate and Heavy Forgings) to Fabricator - Units 2 & 3	Complete	
20	Contractor Issue Final PO to Reactor Vessel Fabricator - Units 2 & 3	Complete	
21	Variable Frequency Drive Fabricator Issue Transformer PO - Units 2 & 3	Complete	
22	Start clearing, grubbing and grading	Complete	
23	Core Makeup Tank Fabricator Issue Long Lead Material PO - Units 2 & 3	Complete	
24	Accumulator Tank Fabricator Issue Long Lead Material PO - Units 2 & 3	Complete	
25	Pressurizer Fabricator Issue Long Lead Material PO - Units 2 & 3	Complete	
26	Reactor Coolant Loop Pipe - Contractor Issue PO to Fabricator - Second Payment - Units 2 & 3	Complete	
27	Integrated Head Package - Issue PO to Fabricator - Units 2 and 3 - second payment	Complete	
28	Control Rod Drive Mechanisms - Contractor Issue PO for Long Lead Material to Fabricator - Units 2 & 3	Complete	
29	Contractor Issue PO to Passive Residual Heat Removal Heat Exchanger Fabricator - Second Payment - Units 2 & 3	Complete	

BLRA Revised Milestones
VC Summer Units 2 and 3

Exhibit No. ____ (SAB-3)

Tracking ID	Milestone Description	Revised Completion Date	Unit
30	Start Parr Road intersection work.	Complete	
31	Reactor Coolant Pump - Issue Final PO to Fabricator - Units 2 and 3	Complete	
32	Integrated Heat Packages Fabricator Issue Long Lead Material PO - Units 2 & 3	Complete	
33	Design Finalization Payment 3	Complete	
34	Start site development	Complete	
35	Contractor Issue PO to Turbine Generator Fabricator - Units 2 & 3	Complete	
36	Contractor Issue PO to Main Transformers Fabricator - Units 2 & 3	Complete	
37	Core Makeup Tank Fabricator Notice to Contractor Receipt of Long Lead Material - Units 2 & 3	Complete	
38	Design Finalization Payment 4	Complete	
39	Turbine Generator Fabricator Issue PO for Condenser Material - Unit 2	Complete	
40	Reactor Coolant Pump Fabricator Issue Long Lead Material Lot 2 - Units 2 & 3	Complete	
41	Passive Residual Heat Removal Heat Exchanger Fabricator Receipt of Long Lead Material - Units 2 & 3	Complete	
42	Design Finalization Payment 5	Complete	
43	Start erection of construction buildings, to include craft facilities for personnel, tools, equipment; first aid facilities; field offices for site management and support personnel; temporary warehouses; and construction hiring office.	Complete	
44	Reactor Vessel Fabricator Notice to Contractor of Receipt of Flange Nozzle Shell Forging - Unit 2	Complete	

BLRA Revised Milestones
VC Summer Units 2 and 3

Exhibit No. ____ (SAB-3)

Tracking ID	Milestone Description	Revised Completion Date	Unit
45	Design Finalization Payment 6	Complete	
46	Instrumentation and Control Simulator - Contractor Issue PO to Subcontractor for Radiation Monitor System - Units 2 & 3	Complete	
47	Reactor Vessel Internals - Fabricator Start Fit and Welding of Core Shroud Assembly - Unit 2	Complete	
48	Turbine Generator Fabricator Issue PO for Moisture Separator Reheater/Feedwater Heater Material - Unit 2	Complete	
49	Reactor Coolant Loop Pipe Fabricator Acceptance of Raw Material - Unit 2	Complete	
50	Reactor Vessel Internals - Fabricator Start Weld Neutron Shield Spacer Pads to Assembly - Unit 2	7/31/2012	Unit 2
51	Control Rod Drive Mechanisms - Fabricator to Start Procurement of Long Lead Material - Unit 2	Complete	
52	Contractor Notified that Pressurizer Fabricator Performed Cladding on Bottom Head - Unit 2	Complete	
53	Start excavation and foundation work for the standard plant for Unit 2	Complete	
54	Steam Generator Fabricator Notice to Contractor of Receipt of 2nd Steam Generator Tubesheet Forging - Unit 2	Complete	
55	Reactor Vessel Fabricator Notice to Contractor of Outlet Nozzle Welding to Flange Nozzle Shell Completion - Unit 2	Complete	
56	Turbine Generator Fabricator Notice to Contractor Condenser Fabrication Started - Unit 2	Complete	

BLRA Revised Milestones
VC Summer Units 2 and 3

Exhibit No. ____ (SAB-3)

Tracking ID	Milestone Description	Revised Completion Date	Unit
57	Complete preparations for receiving the first module on site for Unit 2.	Complete	
58	Steam Generator Fabricator Notice to Contractor of Receipt of 1st Steam Generator Transition Cone Forging - Unit 2	Complete	
59	Reactor Coolant Pump Fabricator Notice to Contractor of Manufacturing of Casing Completion - Unit 2	Complete	
60	Reactor Coolant Loop Pipe Fabricator Notice to Contractor of Machining, Heat Treating & Non-Destructive Testing Completion - Unit 2	Complete	
61	Core Makeup Tank Fabricator Notice to Contractor of Satisfactory Completion of Hydrotest - Unit 2	9/30/2012	Unit 2
62	Polar Crane Fabricator Issue PO for Main Hoist Drum and Wire Rope - Units 2 & 3	Complete	
63	Control Rod Drive Mechanisms - Fabricator to Start Procurement of Long Lead Material - Unit 3	Complete	
64	Turbine Generator Fabricator Notice to Contractor Condenser Ready to Ship - Unit 2	Complete	
65	Start placement of mud mat for Unit 2	6/29/2012	Unit 2
66	Steam Generator Fabricator Notice to Contractor of Receipt of 1st Steam Generator Tubing - Unit 2	Complete	
67	Pressurizer Fabricator Notice to Contractor of Welding of Upper and Intermediate Shells Completion - Unit 2	Complete	
68	Reactor Vessel Fabricator Notice to Contractor of Closure Head Cladding Completion - Unit 3	6/30/2012	Unit 3

BLRA Revised Milestones
VC Summer Units 2 and 3

Tracking ID	Milestone Description	Revised Completion Date	Unit
69	Begin Unit 2 first nuclear concrete placement	8/24/2012	Unit 2
70	Reactor Coolant Pump Fabricator Notice to Contractor of Stator Core Completion - Unit 2	Complete	
71	Fabricator Start Fit and Welding of Core Shroud Assembly - Unit 2	Complete	
72	Steam Generator Fabricator Notice to Contractor of Completion of 1st Steam Generator Tubing Installation - Unit 2	Complete	
73	Reactor Coolant Loop Pipe - Shipment of Equipment to Site - Unit 2	12/31/2012	Unit 2
74	Control Rod Drive Mechanism - Ship Remainder of Equipment (Latch Assembly & Rod Travel Housing) to Head Supplier - Unit 2	6/30/2012	Unit 2
75	Pressurizer Fabricator Notice to Contractor of Welding of Lower Shell to Bottom Head Completion - Unit 2	Complete	
76	Steam Generator Fabricator Notice to Contractor of Completion of 2nd Steam Generator Tubing Installation - Unit 2	5/31/2012	Unit 2
77	Design Finalization Payment 14	Complete	
78	Set module CA04 for Unit 2	11/6/2012	Unit 2
79	Passive Residual Heat Removal Heat Exchanger Fabricator Notice to Contractor of Final Post Weld Heat Treatment - Unit 2	Complete	
80	Passive Residual Heat Removal Heat Exchanger Fabricator Notice to Contractor of Completion of Tubing - Unit 2	5/31/2012	Unit 2

BLRA Revised Milestones
VC Summer Units 2 and 3

Tracking ID	Milestone Description	Revised Completion Date	Unit
81	Polar Crane Fabricator Notice to Contractor of Girder Fabrication Completion - Unit 2	10/31/2012	Unit 2
82	Turbine Generator Fabricator Notice to Contractor Condenser Ready to Ship - Unit 3	8/31/2013	Unit 3
83	Set Containment Vessel ring #1 for Unit 2	1/7/2013	Unit 2
84	Reactor Coolant Pump Fabricator Delivery of Casings to Port of Export - Unit 2	7/31/2012	Unit 2
85	Reactor Coolant Pump Fabricator Notice to Contractor of Stator Core Completion - Unit 3	8/31/2013	Unit 3
86	Reactor Vessel Fabricator Notice to Contractor of Receipt of Core Shell Forging - Unit 3	Complete	
87	Contractor Notified that Pressurizer Fabricator Performed Cladding on Bottom Head - Unit 3	Complete	
88	Set Nuclear Island structural module CA03 for Unit 2	6/26/2013	Unit 2
89	Squib Valve Fabricator Notice to Contractor of Completion of Assembly and Test for Squib Valve Hardware - Unit 2	5/31/2012	Unit 2
90	Accumulator Tank Fabricator Notice to Contractor of Satisfactory Completion of Hydrotest - Unit 3	3/31/2013	Unit 3
91	Polar Crane Fabricator Notice to Contractor of Electric Panel Assembly Completion - Unit 2	3/31/2013	Unit 2
92	Start containment large bore pipe supports for Unit 2	6/28/2013	Unit 2

BLRA Revised Milestones
VC Summer Units 2 and 3

Exhibit No. ____ (SAB-3)

Tracking ID	Milestone Description	Revised Completion Date	Unit
93	Integrated Head Package - Shipment of Equipment to Site - Unit 2	3/31/2013	Unit 2
94	Reactor Coolant Pump Fabricator Notice to Contractor of Final Stator Assembly Completion - Unit 2	5/31/2013	Unit 2
95	Steam Generator Fabricator Notice to Contractor of Completion of 2nd Steam Generator Tubing Installation - Unit 3	6/30/2013	Unit 3
96	Steam Generator Fabricator Notice to Contractor of Satisfactory Completion of 1st Steam Generator Hydrotest - Unit 2	1/31/2013	Unit 2
97	Start concrete fill of Nuclear Island structural modules CA01 and CA02 for Unit 2	4/3/2014	Unit 2
98	Passive Residual Heat Removal Heat Exchanger - Delivery of Equipment to Port of Entry - Unit 2	12/31/2012	Unit 2
99	Refueling Machine Fabricator Notice to Contractor of Satisfactory Completion of Factory Acceptance Test - Unit 2	11/30/2013	Unit 2
100	Deliver Reactor Vessel Internals to Port of Export - Unit 2	1/31/2014	Unit 2
101	Set Unit 2 Containment Vessel #3	4/24/2014	Unit 2
102	Steam Generator - Contractor Acceptance of Equipment at Port of Entry - Unit 2	7/31/2013	Unit 2
103	Turbine Generator Fabricator Notice to Contractor Turbine Generator Ready to Ship - Unit 2	4/30/2013	Unit 2
104	Pressurizer Fabricator Notice to Contractor of Satisfactory Completion of Hydrotest - Unit 3	3/31/2014	Unit 3

BLRA Revised Milestones
VC Summer Units 2 and 3

Tracking ID	Milestone Description	Revised Completion Date	Unit
105	Polar Crane - Shipment of Equipment to Site - Unit 2	1/31/2014	Unit 2
106	Receive Unit 2 Reactor Vessel on site from fabricator	5/13/2014	Unit 2
107	Set Unit 2 Reactor Vessel	6/23/2014	Unit 2
108	Steam Generator Fabricator Notice to Contractor of Completion of 2nd Channel Head to Tubesheet Assembly Welding - Unit 3	12/31/2013	Unit 3
109	Reactor Coolant Pump Fabricator Notice to Contractor of Final Stator Assembly Completion - Unit 3	8/31/2014	Unit 3
110	Reactor Coolant Pump - Shipment of Equipment to Site (2 Reactor Coolant Pumps) - Unit 2	10/31/2013	Unit 2
111	Place first nuclear concrete for Unit 3	10/9/2013	Unit 3
112	Set Unit 2 Steam Generator	10/23/2014	Unit 2
113	Main Transformers Ready to Ship - Unit 2	9/30/2013	Unit 2
114	Complete Unit 3 Steam Generator Hydrotest at fabricator	2/28/2014	Unit 3
115	Set Unit 2 Containment Vessel Bottom Head on basemat legs	10/11/2012	Unit 2
116	Set Unit 2 Pressurizer Vessel	5/16/2014	Unit 2

BLRA Revised Milestones
VC Summer Units 2 and 3

Tracking ID	Milestone Description	Revised Completion Date	Unit
117	Reactor Coolant Pump Fabricator Notice to Contractor of Satisfactory Completion of Factory Acceptance Test - Unit 3	2/28/2015	Unit 3
118	Deliver Reactor Vessel Internals to Port of Export - Unit 3	6/30/2015	Unit 3
119	Main Transformers Fabricator Issue PO for Material - Unit 3	2/28/2015	Unit 3
120	Complete welding of Unit 2 Passive Residual Heat Removal System piping	2/5/2015	Unit 2
121	Steam Generator - Contractor Acceptance of Equipment at Port of Entry - Unit 3	4/30/2015	Unit 3
122	Refueling Machine - Shipment of Equipment to Site - Unit 3	2/28/2015	Unit 3
123	Set Unit 2 Polar Crane	1/9/2015	Unit 2
124	Reactor Coolant Pumps - Shipment of Equipment to Site - Unit 3	6/30/2015	Unit 3
125	Main Transformers Ready to Ship - Unit 3	7/31/2015	Unit 3
126	Spent Fuel Storage Rack - Shipment of Last Rack Module - Unit 3	7/31/2014	Unit 3
127	Start electrical cable pulling in Unit 2 Auxillary Building	8/14/2013	Unit 2
128	Complete Unit 2 Reactor Coolant System cold hydro	1/22/2016	Unit 2

BLRA Revised Milestones
VC Summer Units 2 and 3

Exhibit No. ____ (SAB-3)

Tracking ID	Milestone Description	Revised Completion Date	Unit
129	Activate class 1E DC power in Unit 2 Auxilary Building.	3/15/2015	Unit 2
130	Complete Unit 2 hot functional test.	5/3/2016	Unit 2
131	Install Unit 3 ring 3 for containment vessel	8/25/2015	Unit 3
132	Load Unit 2 nuclear fuel	9/15/2016	Unit 2
133	Unit 2 Substantial Completion	3/15/2017	Unit 2
134	Set Unit 3 Reactor Vessel	10/22/2015	Unit 3
135	Set Unit 3 Steam Generator #2	2/25/2016	Unit 3
136	Set Unit 3 Pressurizer Vessel	7/16/2015	Unit 3
137	Complete welding of Unit 3 Passive Residual Heat Removal System piping	6/16/2016	Unit 3
138	Set Unit 3 polar crane	5/9/2016	Unit 3
139	Start Unit 3 Shield Building roof slab rebar placement	5/26/2016	Unit 3
140	Start Unit 3 Auxiliary Building electrical cable pulling	11/7/2014	Unit 3

DOCKET NO. 2012-203-E
ORDER NO. 2012-_____
__________, 2012
ORDER EXHIBIT NO. 2

BLRA Revised Milestones
VC Summer Units 2 and 3

Exhibit No. _____ (SAB-3)

Tracking ID	Milestone Description	Revised Completion Date	Unit
141	Activate Unit 3 Auxiliary Building class 1E DC power	5/15/2016	Unit 3
142	Complete Unit 3 Reactor Coolant System cold hydro	3/22/2017	Unit 3
143	Complete Unit 3 hot functional test	7/3/2017	Unit 3
144	Complete Unit 3 nuclear fuel load	11/15/2017	Unit 3
145	Begin Unit 3 full power operation	4/8/2018	Unit 3
146	Unit 3 Substantial Completion	5/15/2018	Unit 3